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Transcript Exhibit(s)

Docket #(s): E-01773A-09-0472

Exhibit # : A1-A9, MEC1, MEC2, S1-S6, SBS10, Tricol, Trico2.

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To: Docket Control

Date: November 9, 2010

Re: AEPCO / Rates
E-01773A-09-0472
October 25, 2010

STATUS OF ORIGINAL EXHIBITS

FILED WITH DOCKET CONTROL

AEPCO (A Exhibits)

1 through 9

Trico (Trico Exhibits)

1 and 2

Mohave Electric Cooperative (MEC Exhibits)

1 and 2

Staff (S Exhibits)

1 through 6, 8 through 10

CONFIDENTIAL EXHIBITS

Staff (S Exhibits)

7 Given to ALJ Rodda

Copy to:

Ms. Jane Rodda, Administrative Law Judge
Ms. Maureen Scott, Staff
Mr. Michael M. Grant – AEPCO
Mr. William P. Sullivan – MEC
Mr. Michael W. Patten - Trico

EXHIBIT
A-1
ADMITTED

DIRECT TESTIMONY OF DIRK MINSON
ON BEHALF OF
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
GENERAL RATES APPLICATION

INTRODUCTION

Q. Please state your name and business address.

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

Q. 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 on 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, procedure development and implementation of appropriate financial controls. Additional responsibilities include financial planning, rate design development and implementation, corporate treasury functions, as well as cash and working capital management and inventory control.

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 34-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.

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

2 A. I will provide the Commission information concerning AEPCO, its membership
3 structure, its Board review and approval process for this rate filing and its rate
4 history. I'll also describe generally the rate request and certain issues and other
5 requests concerning it. Gary Pierson, our Manager of Financial Services, will
6 testify specifically concerning the A-F rate filing schedules. Gary Goble of
7 Management Applications Consulting testifies in support of the G and H rate
8 filing schedules.

9

10 **BACKGROUND**

11 **Q. Mr. Minson, please describe AEPCO.**

12 A. AEPCO is a non-profit, generation cooperative which serves the wholesale power
13 needs of its four all-requirements ("ARM") and two partial-requirements
14 ("PRM") Class A Member distribution cooperatives ("distribution cooperatives").
15 The distribution cooperatives provide electricity at retail to their member owners
16 which AEPCO generates or purchases at wholesale. We have one Class A ARM
17 in south-central California—Anza Electric Cooperative, Inc. The three Arizona
18 ARMs are Duncan Valley Electric Cooperative, Inc., Graham County Electric
19 Cooperative, Inc. and Trico Electric Cooperative, Inc. Our two PRMs are
20 Mohave Electric Cooperative, Inc. ("MEC") and Sulphur Springs Valley Electric
21 Cooperative, Inc. ("SSVEC"). The Arizona distribution cooperatives are also
22 regulated by the Commission.

23

24 **Q. What is the difference between an ARM and a PRM?**

25 A. As the name implies, an all-requirements member or ARM has a contract with
26 AEPCO which requires it to buy and AEPCO to plan for and furnish all of its
27 present and future power requirements. A partial-requirements member or PRM,

instead, contracts with AEPCO to furnish only a portion of its retail electricity requirements. That member then plans for and secures from AEPCO or others the balance of its electricity needs. MEC became a PRM in 2001 as part of AEPCO's restructuring, which the Commission approved in Decision No. 63868. SSVEC became a PRM on January 1, 2008. That conversion was approved by the Commission in Decision No. 70105.

Q. Does AEPCO have other members?

A. Yes. The City of Mesa was a Class B Member during a portion of the test year. But, its contract to purchase 15 MW of power and energy from AEPCO expired on December 31, 2008 and it no longer is a member. The Salt River Project is also a Class B AEPCO Member. However, its firm 100 MW electric service purchase agreement with AEPCO will expire next year on December 31, 2010. At that time, its membership will cease. Finally, Valley Electric Association became a Class D Member in 2007. It has a service contract for scheduling and trading services.

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

A. Most of it is produced at our Apache Generating Station located near Wilcox, Arizona. We have approximately 560 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. For example, during the test period, AEPCO had a 15 MW, year-round contract with Public Service Company of New Mexico which expired on December 31, 2008.

1 **Q. How is AEPCO governed?**

2 A. AEPCO's Board of Directors oversees all aspects of our operations. It is
3 comprised of 14 members. Twelve of the Board members (two per Class A
4 Member) are designated as the distribution cooperatives' representatives by the
5 distribution cooperative Boards. Those Boards, in turn, are elected by their retail
6 member/consumers. The remaining two Board members represent the Class B
7 and Class D Members.

8

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

10 A. AEPCO's current rates were authorized by the Commission in Decision
11 No. 68071 and became effective on September 1, 2005. In addition, the Decision
12 approved implementation of a Purchased Power and Fuel Adjustor Clause
13 ("PPFAC"). Decision No. 68071 also ordered AEPCO to file a rate case six
14 months after SSVEC had completed a full calendar year as a partial-requirements
15 member, *i.e.,* July 1, 2009. On April 13, 2009, AEPCO filed a request with the
16 Commission to extend the filing date from July 1 to October 1 in order to
17 facilitate further discussions on cost allocation and rate design issues among its
18 all- and partial-requirements members. The Commission granted AEPCO's
19 request in Decision No. 71112 and authorized AEPCO to file its rate case on
20 October 1 based upon a test year ending March 31, 2009.

21

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

24 A. Yes.

25

26 The process of Board review began this spring. Several Board meetings were
27 held to discuss the need for and the elements of AEPCO's rate filing. In addition,

1 meetings were held with the distribution cooperatives' staffs and consultants to
2 review revenue requirement aspects of the filing and a committee of
3 representatives of Class A Members and the AEPCO staff also discussed certain
4 cost allocation and rate design issues. As we explained in seeking the extension
5 for the rate filing from July 1 to October 1, our purpose in conducting these
6 multiple meetings was to develop as much consensus on as many issues as
7 possible. We did make significant progress on that front.
8
9 AEPCO's Board of Directors approved the filing of this rate case on a non-
10 unanimous basis during its September 2009 meeting. The committee formed to
11 address allocation and rate design issues has not yet reached a final resolution of
12 all issues, but it is attempting to complete a rate settlement agreement on or before
13 December 1, 2009.
14
15 We are hopeful that the members will be able to resolve the remaining cost
16 allocation and rate design issues. However, regardless of that outcome, as I'll
17 explain, for its own revenue requirements, PPFAC and other needs, AEPCO must
18 make this filing now so that new rates can take effect January 1, 2011. We have
19 also prepared this filing based upon cost allocation and rate design principles
20 which we believe are fair and just—taking into account where possible the input
21 of our members on these issues. Mr. Goble discusses these subjects in much
22 greater detail.
23

OVERVIEW OF FILING

Q. Please summarize AEPCO's rate request.

A. Messrs. Pierson and Goble testify concerning the specifics of the request. But, in general, AEPCO requests an overall 2.41% increase in its revenue requirements, which is a blend of a 2.83% decrease in revenues from all-requirements members and a 5.39% increase in revenues from its partial-requirements members. AEPCO further requests that the new rates take effect January 1, 2011 and that AEPCO's PPFAC be continued beyond its currently scheduled expiration date of August 17, 2010.

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

A. In several respects, the rate filing is based upon certain cost causation principles that were developed by the rate design committee. One of these principles involved a change in the methodology by which operations and maintenance expenses were allocated to the all- and partial-requirements customers. Using an allocation method based upon allocated capacity percentages as defined in the respective partial requirements agreements rather than a method based upon the percentage of kW month billing units to total kW month billing units results in a greater percentage of operations and maintenance expenses being assigned to the partial-requirements customers. That is the primary reason for the difference between the rate requests.

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 achieves in its contract and economy sales to others. Thus, the proceeds of these sales to others

are used to reduce the distribution cooperatives' cost of service and, therefore, 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 accounts for about 55% of the costs of the total delivered rate at retail. Assuming a residential rate of 14 cents per kWh, on average eight cents of that rate would be attributable to AEPCO's generation service. Therefore, we estimate that an ARM residential consumer using 1,000 kWh per month would see approximately a $2.00 decrease in the monthly bill and a PRM residential consumer using the same amount would see about a $4.00 increase in the monthly bill as a result of this rate request.

Q. Why is this rate increase necessary?

A. Obviously, AEPCO is subject to the same kind of inflationary pressures which affect all utilities and businesses in general. Many of those costs have increased since the 2003 test year used in our last rate case. In addition to that, generally there are four primary cost changes which are driving the need for this request.

First, our long-term coal arrangements expired at the end of last year and we are seeing much higher delivered coal costs as a result of the new coal contracts which became effective January 1, 2009. AEPCO's 2008 delivered cost of coal was approximately $1.90/MMBtu in 2008, but that has risen to about $3.00/MMBtu this year. Second, this rate application reflects substantial impacts to both AEPCO's costs and revenues as a result of (a) the expiration of the City of Mesa ("Mesa") 15 MW sales agreement on December 31, 2008; (b) the expiration

of the Public Service Company of New Mexico ("PNM") 13 MW purchased power agreement on December 31, 2008; but, most significantly, (c) the expiration of the 100 MW Salt River Project ("SRP") 20-year sales contract on December 31, 2010. Third, most of our generating assets at Apache are now 30 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 are increasing. Finally, in order to meet the mercury control requirements of the Consent Order with the Arizona Department of Environmental Quality, AEPCO will incur significant increased costs starting in January 2011 to inject certain chemicals into the Apache Station coal-fired units combustion process. AEPCO has made a pro forma adjustment to reflect the costs of those chemicals. As Mr. Pierson explains in his testimony, the overall impact of these and other adjustments on net margins is a decrease of more than $15 million.

Q. Did the foregoing four factors affect AEPCO's financial performance in 2008 and 2009?

A. Yes. AEPCO is already experiencing the effects of the increase in coal costs, higher maintenance outage overhaul costs and the expirations of the Mesa sales and PNM purchase contracts. The revenue and cost impacts resulting from expiration of the Salt River Project contract and the new mercury control chemical costs will commence on January 1, 2011. That is why we are requesting that the new rates not take effect until that date.

Q. What level of margins is AEPCO requesting in this rate application?

A. AEPCO is requesting operating margins of $3.4 million. On a cash basis, the requested margins would generate approximately $5.0 million of working capital

on an annual basis. AEPCO has reviewed its working capital needs going forward and determined that approximately $20 million in working capital is and will be necessary to support operational requirements. The requested small level of margins will begin to build toward that working capital level over the next several years.

Although AEPCO had positive margins from 2005 to 2008, it did not build higher levels of working capital. AEPCO's working capital was severely strained over that period—funding, among other things, under-collections in the fuel bank caused by volatile fuel costs; paying for a principal "bubble" caused by required principal payments which exceeded the depreciation levels built into current rates; and providing the substantial sums needed to cover its construction costs until loan funds can be drawn to reimburse expenditures when those construction projects are finally completed. For example, our construction expenditures as of March 31 of this year were almost $26 million—more than seven times the requested operating margin amount.

As a result of these cash and working capital demands, since 2005, AEPCO has had to use its operating line of credit extensively. It hit a high month-end drawn balance on the credit line of about $19 million in 2006. As of March 31, 2009, AEPCO still had an outstanding drawn balance of $15.8 million on that line. Currently, the balance is down to approximately $8.0 million. The requested margins will allow AEPCO to continue to reduce its line of credit balance and gradually build the necessary level of working capital that it needs to fund operations. Those margins will also reduce the interest expense and the associated cost of service which our members must pay.

1 **OTHER ISSUES**

2 Q. **Mr. Minson, is AEPCO also requesting continuation of its PPFAC in this**
3 **proceeding?**

4 A. Absolutely. Mr. Pierson discusses the details of that request in his testimony and
5 Mr. Goble sponsors the PPFAC bases in his testimony. As AEPCO's CFO, I
6 can't stress strongly enough the vital role the PPFAC has played since AEPCO's
7 last rate case in assuring literally that the lights stayed on in rural Arizona. Even
8 with the clause, as I just discussed, our operating margins, available cash and line
9 of credit were strained to the breaking point in 2006 and 2007. While the markets
10 have calmed somewhat from those extremes, they still remain very volatile. For
11 example, while we were negotiating a new agreement to replace our expiring coal
12 contract, Powder River Basin coal prices moved up more than 50% from early
13 2007 to the end of 2008 and the price of Uinta Basin coal from Colorado more
14 than doubled. Conversely, in just the past year, there has been a natural gas price
15 decrease of 80% from $9.50/Dth in April 2009 from the San Juan Blanco Basin to
16 $1.94/Dth in September 2009. While that's obviously good news currently, it
17 also reinforces the facts that very volatile fuel prices continue and the PPFAC is
18 critical to continue to address them.

19

20 AEPCO is also concerned with the potential magnitude of carbon taxes, cap and
21 trade allowances or similar carbon levies that are being proposed in Congress.
22 We also ask that AEPCO be authorized to recover these costs, if they materialize,
23 through the PPFAC.

24

1 **Q. Are there any events that may require AEPCO to supplement or revise the**
2 **rate relief requested in this rate case?**
3 A. Yes. We have made a labor expense adjustment in this filing to reflect an increase
4 in contributions that AEPCO must pay to the National Rural Electric Cooperative
5 Association ("NRECA") for participation in its Retirement and Security Program
6 (AEPCO's pension plan for employees). It's possible that AEPCO may have to
7 make additional contributions in 2010 and/or 2011 in the form of a Deficit Recovery
8 Charge dependent upon NRECA's annual evaluation of the market value of the
9 program's investments. If that occurs, we may file an amendment on that subject.
10 Also, the discussions I mentioned previously among our members may or may not
11 require an alteration to our request.
12
13 **CONCLUSION**
14 **Q. Do you have any concluding remarks?**
15 A. I would ask that the Commission enter its Order authorizing the implementation
16 as of January 1, 2011 of the all-requirements and partial-requirements rates we
17 have requested. We'd also ask that the Commission approve continuation of the
18 PPFAC with the modifications discussed.
19
20 **Q. Does that conclude your direct testimony?**
21 A. Yes, it does.

EXHIBIT
A-2
ADMITTED

DIRECT TESTIMONY OF GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

GENERAL RATES APPLICATION

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

A. My name is Gary E. Pierson. My business address is 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 and cash management functions for Sierra Southwest. In addition, under agreements that Sierra Southwest has with Arizona Electric Power Cooperative, Inc. ("AEPCO") and Southwest Transmission Cooperative, Inc. ("SWTC"), I am responsible for the same functions as well as rate design and implementation for these two cooperatives.

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 17 years in various positions in the areas of ratemaking, budgeting, financial forecasting and power

requirements studies. In May 1992, I joined 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. 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?

A. I will testify in support of the application for a general rate filing for AEPCO. My testimony is primarily directed to financial schedules A-F which were filed in support of the application. Mr. Goble will testify concerning schedules G and H.

Q. Mr. Pierson, before discussing those schedules, please summarize AEPCO's revenue requirements and rate design requests.

A. AEPCO is asking that the Commission approve a revenue increase of $4.023 million dollars or a 2.41% increase in revenue requirements. That average increase, however, is actually a blend of a 2.83% decrease in the revenues from rates for the all-requirements members and a 5.39% increase in the revenues from rates for the partial-requirements members.

Further, as a result of numerous meetings with the members over the last several years and the development of certain cost causation principles, AEPCO is also proposing modifications to the rate designs that were approved by the Commission in the last rate

filing. One of these cost causation principles involves a change in the methodology by which operations and maintenance expense is allocated to the all-requirements members ("ARMs") and the partial-requirements members ("PRMs"). As a result, AEPCO is proposing that the PRMs' O&M rates be changed from a per kW/Month unit rate to a fixed monthly charge. Another of these cost causation principles involves a change in the methodology by which energy-related expenses are allocated to the all-requirements and partial-requirements members. As a result, AEPCO is proposing that the current single energy rate per kWh be subdivided into Base Resources, Other Existing Resources and Additional ARM Resources energy rates for the ARMs and PRMs, as applicable. Also, AEPCO requests that costs recovered through the Purchased Power Fuel Adjustor Clause ("PPFAC") be applied to the same rate categories to be consistent with the proposed energy rate structure.

The following is a summary of present and proposed rate structures:

	Present Rates	**Proposed Rates**
All-Requirements Members:		
Demand Rate	$14.98/kW Month	$14.05/kW Month
Energy Rates:		
Base Resources		$0.03236/kWh
Other Existing Resources		$0.06730/kWh
Additional ARM Resources		$0.07341/kWh
Energy Rate	$0.02073/kWh	$0.03722/kWh (Average)

Partial-Requirements Members:

MEC:

Fixed Charge	$855,113/Month	$772,376/Month
O&M Charge	$7.26/kW Month	$1,410,263/Month
Energy Rates:		
Base Resources		$0.03216/kWh
Other Existing Resources		$0.06879/kWh
Energy Rate	$0.02073/kWh	$0.03595/kWh (Average)

SSVEC:

Fixed Charge	$757,429/Month	$683,919/Month
O&M Charge	$7.26/kW Month	$1,248,752/Month
Energy Rates:		
Base Resources		$0.03230/kWh
Other Existing Resources		$0.06676/kWh
Energy Rate	$0.02073/kWh	$0.03672/kWh (Average)

In relation to the current energy rate of $0.02073, I would note that the total energy rate charged the members is higher than that energy rate because of the additional PPFAC adjustors which are charged the ARMs and PRMs per kWh of energy use.

Q. Please describe the schedules.

A. They are a multi-page exhibit containing the schedules A-H (the "Schedules") that are described in A.A.C. R14-2-103.B 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 rate filing's summary schedules. Schedule A-1 shows the computation of the increase in gross revenue requirements which results from the development of the financial schedules.

As Schedule A-1 shows, the proposed revenue increase of $4.023 million is an increase of 2.41% over the revenues generated by present rates. Current rates produced approximately $529,000 in net margins in the test year ended March 31, 2009, as adjusted. Based upon a test period adjusted rate base of $231.8 million, these proposed revenue requirements generate a rate of return of 6.62%.

Schedule A-2 summarizes results of operations for the 12 months ending March 31, 2007, 2008 and 2009 and the adjusted test year with present rates and with proposed rates. As I mentioned, on an adjusted test year basis, the Test Year Adjusted column shows that AEPCO had a net margin of $529 thousand, a TIER of 1.05 and a DSC of 1.12 in the test year. Under the proposed rates, AEPCO would have a net margin of about $4.5 million, a TIER of 1.42 and a DSC of 1.35 in the test year. Schedule A-3 summarizes AEPCO's capital structure and capitalization ratios for the years ended March 31, 2007 and 2008 as well as the test year and projected year. Schedule A-4 provides data concerning construction expenditures, net plant additions and gross utility plant in service. 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 $231.8 million, as of March 31, 2009. It includes gross utility plant in service of $399.4 million, accumulated depreciation and amortization of $204.8 million, allowances for working capital of $21.8 million, plant held for future use of $2.6 million and deferred debits of $12.8 million. No adjustments were made to the original cost rate base for the test year (Schedule B-2). Schedules B-3 and B-4, concerning reconstructed cost new less depreciation ("RCND") rate base, have not been completed. As a non-profit cooperative, AEPCO stipulates to the use of its original cost rate base as its fair value rate base.

Schedule B-5, page 1 provides the computation of working capital by components, which sum to total working capital of $21.8 million and the remaining pages show the calculation of the different components. Schedule B-5, page 2, concerning the calculation of cash working capital, has not been completed. Due to the considerable time and expense of preparing a lead/lag study, AEPCO agrees to the use of a zero value for its cash working capital. Nor is AEPCO asking for prepayments to be included in the computation of rate base as shown on Schedule B-5, page 5, because of the position Staff took on this issue in our 2004-2005 rate case.

Q. Please describe Section C of the Schedules.

A. Section C contains adjusted test year income statements and supporting schedules to the income statements. Schedule C-1, pages 1 through 4, provides the actual income statement and the as-adjusted income statement for the test year. Pages 1 and 2 of Schedule C-1 provide per books and reclassified test year income statements for the test year. The first column displays the revenues and expenses of AEPCO during the test year, which is the 12 months ending March 31, 2009. As noted on Schedule C-1, page 2, AEPCO had operating margins of $14.9 million and non-operating margins of $945 thousand that together produced a net margin of $15.8 million. The second column represents reclassification adjustments that are made to the test period which have a zero effect on net margins of AEPCO.

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

Reclassification Adjustments – Schedule C-2, Pages 1 and 2:

1. SWTC Revenue Reclassification – This adjustment reclassifies the network service and system control and load dispatching revenues that AEPCO collects from its all-requirements members and then pays to SWTC. These revenues and charges are a pass-through at cost of network services provided by SWTC to AEPCO's all-requirements Class A Members. Therefore, AEPCO has removed them from its cost of service. The net effect of this and the other three reclassifications on net margins discussed below is zero.
2. ACC Gross Operating Revenue Assessment – This adjustment reclassifies the revenues that AEPCO receives from its Class A Members against the expense that it records in administrative and general expenses.
3. Coal Legal Expenses – This adjustment reclassifies certain legal expenses that have been recorded in coal expense to administrative and general expenses to be consistent with the rate treatment afforded these expenses in AEPCO's last rate case.
4. Property Tax Reclassification – This adjustment reclassifies property taxes, which are recorded in various operation and maintenance expense categories according to Rural Utilities Service accounting procedures, to taxes so that these expenses can be shown separately for ratemaking purposes.

Pro Forma Adjustments – Schedule C-2, Pages 3 through 10:

1. Coal Cost Adjustment – AEPCO's long-term coal agreement expired at the end of 2008. After approximately two years of planning in relation to and negotiation of new

agreements, new contracts took effect on January 1, 2009 during the final quarter of the test year. This adjustment annualizes revenues and expenses to reflect the new coal costs, which are expected to average $3.01/MMBtu during 2009. AEPCO has included an additional $8.6 million of revenues expected from contractual sales and $23.6 million of additional expenses associated with these contracts. The effect of this adjustment decreases net margins by $14.9 million.

2. Labor Expense Adjustment – This adjustment annualizes labor expense and associated payroll taxes and benefits to reflect wage increases that occurred during the test period and the wage increase that takes effect on the date of this filing, October 1, 2009. In addition, this adjustment reflects the increase in contributions that AEPCO is obligated to pay to the National Rural Electric Cooperative Association for participation in its Retirement and Security Program, which is AEPCO's pension plan for employees. The effect of this adjustment decreases net margins by $1.5 million.

3. Salt River Project Contract Expiration Adjustment – Since 1990, AEPCO has been selling firm capacity of initially 50 MW and then 100 MW to the Salt River Project ("SRP"). This contract, which was approved by the Commission in Decision No. 56101 dated August 31, 1988, expires on December 31, 2010. This adjustment reflects the test year effect of the expiration of that 100 MW sales contract. Hourly generation and purchased power dispatches in connection with this contract have been reviewed to reflect decreased generation and purchased power expenses that would have occurred if this contract had not been in effect during the test year. In addition, AEPCO has also eliminated the associated charges that were paid to SWTC to wheel the power associated with this contract. The effect of these adjustments decreases net margins by

$13.2 million. However, as I discuss shortly, other adjustments have been made to increase AEPCO revenues as a result of increased sales (with related expenses) which are expected to occur as a result of the availability of this 100 MW.

4. City of Mesa Contract Expiration Adjustment – This adjustment annualizes the test year effect of the expiration of the 15 MW sales contract to the City of Mesa ("Mesa") that occurred last year on December 31, 2008. This agreement was approved by the Commission on May 1, 1991 in Decision No. 57343. AEPCO has reviewed the hourly generation and purchased power dispatched in connection with this contract as to decreased generation and purchased power expenses that would have occurred if this contract had not been in effect during the test year. In addition, AEPCO has eliminated the associated charges that were paid to SWTC to wheel the power associated with this contract. This adjustment decreases net margins by $2.3 million. However, as with the SRP contract, I discuss associated increased revenue adjustments below.

5. Public Service Company of New Mexico Contract Expiration Adjustment – This adjustment annualizes the test year effect of the expiration of the purchased power contract with Public Service Company of New Mexico ("PNM") that occurred on December 31, 2008. AEPCO has reviewed the hourly generation and purchased power that was dispatched in connection with this contract as to the decreased purchased power expenses that would have occurred if this contract had not been in effect during the test year. This adjustment increases net margins by $4.7 million.

6. MEC Additional Sales Adjustment – This adjustment reflects the effects of the additional capacity allocated to Mohave Electric Cooperative, Inc. ("MEC") under the terms of its partial-requirements agreement as a result of the expirations of the SRP,

Mesa and PNM contracts. AEPCO has reviewed the hourly generation and purchased power that was dispatched in connection with the MEC partial-requirements contract and made assumptions as to increased sales, additional fuel costs associated with such sales, resource transfers to other parties and displacement of other resources that would have occurred if this additional capacity had been available to MEC during the test year. The effect of this adjustment results in an increase in net margins of $5.3 million.

7. SSVEC Additional Sales Adjustment – Similarly, this adjustment reflects the effects of the additional capacity allocated to and additional impacts as described above in relation to Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") under the terms of its partial-requirements agreement as a result of the expirations of the SRP, Mesa and PNM contracts. This adjustment increases net margins by $3.9 million.

8. All-Requirements Members Coal and Purchased Power Adjustment – Similarly, this adjustment annualizes the effects of the changes in resources that would have occurred for the all-requirements members as a result of the expirations of the SRP, Mesa and PNM contracts. Based on the same review and analysis process described above in relation to MEC, the effect of this adjustment is to increase net margins by $6.5 million.

9. Maintenance Outage Adjustment – This adjustment to test period costs amortizes minor outage expenses over a two-year period and major outage expenses over a six-year period. This adjustment results in a decrease in net margins of $2.1 million.

10. SAP Software Amortization – This adjustment annualizes the amortization of the expenses associated with the installation of the Systems Applications Products ("SAP") software at AEPCO over a seven-year period which started during the test year. This adjustment decreases net margins by $825 thousand.

11. Mercury Control Adjustment – This adjustment reflects the chemical costs which will be incurred as a result of the 50% reduction in mercury emissions requirement, starting in the year 2011, pursuant to the consent decree dated January 30, 2009 between AEPCO and the Arizona Department of Environmental Quality. This adjustment decreases net margins by $2.8 million.

12. Southpoint PPA Capacity Adjustment – This adjustment reduces the Southpoint contract capacity from 30 MW to 25 MW to reflect the effect of the expirations of the SRP, Mesa and PNM contracts. This adjustment increases net margins by $232 thousand.

13. Rate Case Expense Amortization – This adjustment assumes legal and rate consultant costs associated with the rate application of $480,000 and amortizes those expenses over a three-year period. The effect of this adjustment results in a decrease in net margins of $160 thousand.

14. Interest Expense Adjustment – This adjustment annualizes interest expense based upon debt balances and interest rates at the end of the test year, which increases interest expense by $231 thousand. Net margins are decreased by the same amount. In addition, AEPCO has adjusted the principal payments for the test period to reflect extended maturity dates on certain FFB notes that was accomplished on December 31, 2008. This reduced principal payments by $7.3 million.

15. Fuel and Purchased Power Synchronization – This adjustment increases revenues to synchronize the Fuel and Purchased Power Adjustor Clause revenues with the pro forma fuel and purchased power energy costs discussed in previous adjustments. This increases margins by $2.0 million.

1 As indicated on page 10 of Schedule C-2, the total of these pro forma adjustments to
2 expenses and revenues resulted in a decrease in net margins of $15.3 million.
3
4 Finally, Schedule C-3 states the computation of the gross revenue conversion factor.
5
6 **Q. Please describe Section D of the Schedules.**
7 A. The D Schedules contain information on AEPCO's cost of capital for the 12 months ended
8 March 31, 2007, 2008 and 2009 and projected 12 months ended March 31, 2010.
9 Schedule D-1 sets forth the computed cost of capital as of March 31, 2009 for the actual and
10 projected year ended March 31, 2010. Invested debt capital amounted to $193.9 million
11 with a composite cost rate of 5.92%. Schedule D-2 shows long-term and short-term debt
12 balances by lender that comprise the total; the interest rates associated with the debt
13 balances; and the computation of the composite cost rate for three actual years and the
14 projected year. Schedules D-3 and D-4 on preferred stock and common equity are not
15 applicable to AEPCO because it is a member-owned, non-profit cooperative.
16
17 **Q. Please describe Section E of the Schedules.**
18 A. Section E contains financial statements and statistical schedules for the 12 months ending
19 March 31, 2007, 2008 and 2009. Schedule E-1 provides comparative balance sheets and
20 Schedule E-2 shows comparative income statements. Schedule E-3 provides a comparative
21 statement of changes in financial position and Schedule E-4 reflects changes in equity.
22 Schedule E-5 provides detail of utility plant additions during the test year and balances as of
23 March 31, 2008 and 2009. Schedule E-6 is not applicable to AEPCO. Schedule E-7

1 provides AEPCO operating statistics, while Schedule E-8 lists taxes charged to operations.
2 Attached to my testimony as Exhibit GEP-1 are the Consolidated Financial Statements
3 which include the Independent Auditor's Report to the AEPCO Board of Directors dated
4 May 13, 2009. It contains the information that is referenced in Schedule E-9.
5
6 **Q. Finally, please describe Section F of the Schedules.**
7 A. Section F contains various projections and forecast schedules. Schedule F-4 discusses
8 certain assumptions used in developing the projections contained in the previous F
9 schedules.
10
11 **Q. Concerning the PPFAC, does AEPCO have recommendations regarding it?**
12 A. Yes. AEPCO requests that the Commission approve continuation of the adjustor
13 mechanism authorized in the 2005 rate decision with certain modifications. As a result of
14 discussions with the Class A Members, AEPCO is proposing energy rates that are based
15 upon three separate cost pools for MEC, SSVEC and the all-requirements members, as
16 applicable. Mr. Goble discusses this concept in greater detail in his testimony. Consistent
17 with these separate energy rates, separate PPFAC power cost bases will be established for
18 the Base Resources pool and the Other Existing Resources pool for MEC and SSVEC. For
19 all-requirements members, separate PPFAC bases will be established for a Base Resources
20 pool, the Other Existing Resources pool and the Additional ARM Resources pool.
21 **Q. Please discuss any other PPFAC issues.**
22 A. We will work with Staff to refine details, but basically the same monthly reporting and
23 semi-annual filing/adjustment procedures would be followed that have been in place for the

1 past several years. The adjustor bases shown on Exhibit GLG-2 are the recommended
2 clause bases. Finally, AEPCO also requests that any carbon taxes, CO2 Cap and Trade
3 Allowances or similar levies, if any, mandated in the future be allowed to be recovered
4 through the PPFAC.
5
6 **Q. Does this conclude your direct testimony?**
7 A. Yes, it does.

EXHIBIT GEP-1

Exhibit GEP-1

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

INDEPENDENT AUDITOR'S REPORT AND FINANCIAL STATEMENTS

DECEMBER 31, 2008 AND 2007

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INDEPENDENT AUDITOR'S REPORT

The Board of Directors
Arizona Electric Power Cooperative, Inc.

We have audited the accompanying balance sheets of Arizona Electric Power Cooperative, Inc. (the Cooperative) as of December 31, 2008 and 2007 and the related statements of revenues and expenses and unallocated accumulated margins and cash flows for the years then ended. These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Cooperative as of December 31, 2008 and 2007 and the results of its operations and cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

In accordance with *Government Auditing Standards,* we have also issued a report dated May 13, 2009 on our consideration of the Cooperative's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be considered in conjunction with this report in considering the results of our audit.

Moss Adams LLP

Portland, Oregon
May 13, 2009

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
BALANCE SHEETS

ASSETS

	DECEMBER 31, 2008	DECEMBER 31, 2007
UTILITY PLANT		
Plant in service	$ 402,042,682	$ 393,889,048
Construction work in progress	20,108,331	3,128,219
Total utility plant	422,151,013	397,017,267
Less accumulated depreciation	204,728,929	198,830,152
Utility plant, net	217,422,084	198,187,115
INVESTMENTS		
Restricted held to maturity	9,862,193	6,313,693
Unrestricted	7,166,123	7,149,486
Total investments	17,028,316	13,463,179
CURRENT ASSETS		
Cash and cash equivalents		
General unrestricted	1,138,577	6,426,466
Restricted	3,871,394	3,776,700
Accounts receivable	20,661,593	21,611,126
Accumulated under-recovered fuel and purchased power costs	7,238,080	5,593,468
Inventories, at average cost		
Coal and natural gas	19,099,253	8,520,622
Materials and supplies	6,919,946	6,307,932
Prepayments and other current assets	978,377	1,166,881
Notes receivable	58,739	86,873
Total current assets	59,965,959	53,490,068
DEFERRED DEBITS	9,464,344	6,199,874
Total assets	$ 303,880,703	$ 271,340,236

See accompanying notes.

MEMBERSHIP CAPITAL AND LIABILITIES

	DECEMBER 31,	
	2008	2007
MEMBERSHIP CAPITAL		
Membership fees	$ 430	$ 430
Patronage capital	57,201,869	25,454,747
Unallocated accumulated margins	17,355,770	31,747,122
Total membership capital	74,558,069	57,202,299
LONG-TERM DEBT		
Federal Financing Bank	109,018,862	110,748,768
Cooperative Utility Trust	19,351,712	21,116,169
Solid Waste Disposal Revenue Bonds	14,765,608	15,372,414
Cooperative Finance Corporation	29,300,244	932,281
Rural Utilities Service	107,908	674,423
Captial lease obligation	4,651,289	2,336,012
Total long-term debt	177,195,623	151,180,067
CURRENT LIABILITIES		
Member advances and other investments	18,541,623	17,760,555
Current maturities of capital lease obligation	1,260,950	448,045
Current maturities of long-term debt	6,645,314	16,457,993
Accounts payable	13,307,282	7,230,981
Accrued property and business taxes	2,229,488	2,212,431
Accrued interest	725,295	965,725
Line of credit - Cooperative Finance Corporation	5,400,000	13,943,050
Other	1,097,548	897,665
Total current liabilities	49,207,500	59,916,445
ASSET RETIREMENT OBLIGATIONS	1,654,712	1,439,346
DEFERRED CREDITS	1,264,799	1,602,079
Total membership capital and liabilities	$ 303,880,703	$ 271,340,236

See accompanying notes.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
STATEMENTS OF REVENUES AND EXPENSES AND UNALLOCATED ACCUMULATED MARGINS

	YEAR ENDED DECEMBER 31,	
	2008	2007
OPERATING REVENUES		
Sales of electric energy		
Members		
Class A - Firm	$ 123,646,648	$ 138,437,318
Class A - Non Firm	-	177,397
Class B	42,938,769	6,675,767
Class C	-	33,716,073
Class D	1,593,208	2,717,522
Under-recovery of fuel and purchase power costs	38,638,375	24,672,520
Nonmembers	8,402,255	5,400,208
Other, net	728,133	981,112
Total operating revenues	215,947,388	212,777,917
OPERATING EXPENSES		
Power generation		
Fuel	69,854,969	68,096,074
Operation	10,581,716	10,023,850
Maintenance	15,322,190	16,244,572
Purchased power and interchange	52,328,850	41,230,238
Administration and general	10,843,391	9,674,147
Depreciation, amortization and accretion	8,054,263	7,900,636
Transmission	18,526,791	25,955,050
Property and other taxes	2,934,495	3,340,972
Reduction in asset retirement obligation estimate	-	(1,210,453)
Total operating expenses	188,446,665	181,255,086
OPERATING MARGIN	27,500,723	31,522,831
Interest and interest related expenses, net	(11,393,082)	(12,978,824)
Other income, net	1,248,129	2,005,528
NET MARGIN	**17,355,770**	**20,549,535**
UNALLOCATED ACCUMULATED MARGINS, beginning of year	31,747,122	18,849,096
PATRONAGE CAPITAL ALLOCATION	(31,747,122)	(7,651,509)
UNALLOCATED ACCUMULATED MARGINS, end of year	$ 17,355,770	$ 31,747,122

See accompanying notes.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
STATEMENTS OF CASH FLOWS

	YEAR ENDED DECEMBER 31, 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES		
Net margin	$ 17,355,770	$ 20,549,535
Adjustments to reconcile net margin to net cash from operating activities		
Depreciation and amortization	8,054,263	7,811,346
Amortization of deferred charges	77,989	84,480
Amortization of other deferred credits	(337,280)	(337,280)
Patronage capital allocations	(101,528)	(179,791)
Accretion of asset retirement obligations	95,185	89,290
Settlement of asset retirement obligations	-	(1,210,453)
Changes in assets and liabilities		
Restricted cash and cash equivalents	(94,694)	(496,618)
Accounts and notes receivable	977,667	(4,093,929)
Accumulated under-recovered fuel and purchased power costs	(1,644,612)	5,474,080
Inventories	(11,190,645)	(2,460,815)
Prepayments and other current assets	188,504	(185,721)
Deferred debits	(3,342,459)	1,111,405
Accounts payable	6,076,301	(2,254,135)
Accrued interest	(240,430)	(2,223,937)
Accrued overhaul	-	4,353,314
Accrued property and business taxes and other	216,940	499,836
Net cash from operating activities	16,090,971	26,530,607
CASH FLOWS FROM INVESTING ACTIVITIES		
Construction expenditures, net	(23,919,051)	(4,865,794)
Purchases and redemptions of investments, net	(3,463,609)	2,246,457
Net cash from investing activities	(27,382,660)	(2,619,337)
CASH FLOWS FROM FINANCING ACTIVITIES		
Membership fees	-	100
Member advances and other investments, net	781,068	7,031,039
Proceeds from long-term debt	30,386,500	-
Line of credit activity, net	(8,543,050)	(5,056,950)
Payments on long-term debt and capital lease obligation	(16,620,718)	(27,637,469)
Net cash from financing activities	6,003,800	(25,663,280)
CHANGE IN CASH AND CASH EQUIVALENTS	(5,287,889)	(1,752,010)
CASH AND CASH EQUIVALENTS, beginning of year	6,426,466	8,178,476
CASH AND CASH EQUIVALENTS, end of year	$ 1,138,577	$ 6,426,466

See accompanying notes.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
STATEMENTS OF CASH FLOWS

	YEAR ENDED DECEMBER 31,	
	2008	2007
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Cash paid for interest, net of amount capitalized	$ 11,555,523	$ 15,118,281
Noncash investing activities		
Liabilities incurred for asset retirement obligations	$ 120,181	$ 112,742
Assets acquired under a capital lease	$ 3,250,000	$ 502,173

See accompanying notes.

Note 1 - Organization

Arizona Electric Power Cooperative, Inc. (the Cooperative) is a member owned, nonprofit Arizona rural electric generation cooperative organized in 1961 to provide wholesale electric power to its member distribution cooperatives, municipalities and other customers.

Membership of the Cooperative is restricted to electric utilities. The Cooperative has four classes of members. Class A members consist of four distribution cooperatives with all requirements contracts and two distribution cooperatives with partial requirements contracts. Class B members consist of two electric utilities with partial requirements contracts. As of December 31, 2008 there were no Class C members. In 2007, a Class D member was added, representing electric utilities other than Class A, B, or C with a written agreement for power and/or energy and/or substantial service, represented jointly by one director. Class A, Class B, Class C and Class D members are collectively referred to herein as members.

Note 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 of America 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.

Accounting for the effects of regulation - The Cooperative prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standard (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation. SFAS No. 71 requires a cost-based, regulated enterprise to recognize revenues and expenses in the time periods when the revenues and expenses are included in rates. This may result in regulatory assets and liabilities until such time that the related revenues and expenses are included in rates.

Utility plant - Utility plant, consisting primarily of coal and natural gas electric generation facilities, is stated at historical cost and includes the costs of outside contractors, direct labor and materials, allocable overhead and interest charged during 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, is credited to CWIP. Interest costs capitalized on construction projects was approximately $180,000 and $156,000 for 2008 and 2007, respectively.

Note 2 - Summary of Significant Accounting Policies (Continued)

Depreciation is computed on the straight-line basis over estimated useful lives of depreciable property in accordance with rates prescribed by RUS, averaging 2.0% in 2008 and 2007. 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 any losses resulting from impairment of its long-lived assets.

Asset retirement obligations - SFAS No. 143 requires the recognition of an Asset Retirement Obligation (ARO), measured at estimated fair value, for legal obligations related to decommissioning and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. The initial capitalized asset retirement costs are depreciated over the life of the related asset, with accretion of the ARO liability classified as an operating expense.

Investments - The Cooperative accounts for 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, 2008 and 2007, all investment balances were classified as held-to-maturity securities and are therefore recorded at amortized cost (See Note 3).

A decline in the market value of held-to-maturity securities below cost that is deemed to be other-than-temporary results in a reduction in carrying amount to fair value. The impairment is charged to margins and a new cost basis for the security is established. To determine whether an impairment is other-than-temporary, the Cooperative considers whether it has the ability and intent to hold the investment until a market price recovery and considers whether evidence indicating the cost of the investment is recoverable outweighs evidence to the contrary. Evidence considered in this assessment includes the reasons for the impairment, the severity and duration of the impairment, changes in value subsequent to year end and forecasted performance of the investee. Management does not believe the investments are impaired as of December 31, 2008.

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

Receivables - Receivables are recorded when invoices are issued and are written off when they are determined to be uncollectible. The allowance for doubtful accounts is estimated based on historical losses, review of specific problem accounts, the existing economic conditions in the industry and the financial stability of customers. Generally, accounts receivable are considered past due after 30 days. No allowance was deemed necessary at December 31, 2008 and 2007.

Note 2 - Summary of Significant Accounting Policies (Continued)

Inventories - Inventories, consisting of coal, natural gas and materials and supplies, are carried at average cost.

Deferred debits and credits - Deferred debits and 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.

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 - The Cooperative accounts for major and minor overhauls using the deferral method. Accordingly, incurred overhaul costs are deferred and amortized over the overhaul benefit period, generally two years for minor overhauls and six years for major overhauls. The frequency of overhauls is based on the operating characteristics and operating profiles of each generating unit. See Note 7.

Revenues, purchased power and fuel costs - Revenues are recognized as electric power and other energy service products are delivered at rates approved by the ACC. Purchased power and fuel costs are charged to expense as incurred.

In its April 15, 2005 rate order, the ACC approved a fuel and purchased power cost adjustor (the adjustor) for the Cooperative. This adjustor enables the Cooperative to accumulate its over and under collection of fuel and purchased power costs and subsequently, as approved by the ACC, refund or collect from its members the amount of over and under collection of fuel and purchased power costs. Such amounts are recorded as revenue in the period the costs are incurred.

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 using the best available information and present value calculations are used by the Cooperative for purpose of disclosure. For current financial instruments, the carrying amounts approximate fair value.

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 these estimates.

Reclassifications - Certain reclassifications were made to the prior year financial statements to conform to the current year presentation. Such reclassifications had no impact on previously reported net margin.

Note 3 - Investments

Investments at December 31 consist of the following:

	2008		
	Amortized Cost	Unrealized Gain	Fair Value
Restricted - municipal bonds	$ 2,807,111	$ 125,986	$ 2,933,097
Restricted - term certificates	7,055,082	-	7,055,082
Investment in associated organizations	3,979,809	-	3,979,809
Patronage capital	3,186,314	-	3,186,314
Total	$ 17,028,316	$ 125,986	$ 17,154,302

	2007		
	Amortized Cost	Unrealized Gain	Fair Value
Restricted - municipal bonds	$ 2,807,111	$ 142,510	$ 2,949,621
Restricted - term certificates	3,506,582	-	3,506,582
Investment in associated organizations	3,981,212	-	3,981,212
Patronage capital	3,168,274	-	3,168,274
Total	$ 13,463,179	$ 142,510	$ 13,605,689

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

	2008		2007	
	Cost	Fair Value	Cost	Fair Value
Due from one year to five years	$ 3,617,472	$ 3,617,565	$ -	$ -
Due from six years to ten years	14,954	15,161	15,065	15,065
Due after ten years	6,229,767	6,355,453	6,298,628	6,441,138

Municipal bonds - 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 purchased a non-interest bearing Debt Service Reserve Certificate (the certificate) maturing in 2024 upon final payment of the debt. The proceeds of the certificate are held by CFC in a Debt Service Reserve Fund (DSRF). One of the underlying investments, totaling approximately $2,762,000 and maturing in 2022, has a call feature exercisable by the issuer beginning in 2008.

Note 3 - Investments (Continued)

Term certificates - The Cooperative is a member of CFC, a not-for-profit cooperative financing institution. As a condition of membership, the Cooperative purchased Subscription Capital Term Certificates (SCTCs). The SCTCs, totaling $2,759,517 at December 31, 2008 and 2007, bear interest at 5% per annum and have maturity dates ranging from 2070 to 2080.

As a condition of the Solid Waste Disposal Revenue Bonds (See Note 8), which are guaranteed by CFC, the Cooperative purchased a Subordinated Term Certificate (STC). The STC, totaling $708,000 and $732,000 at December 31, 2008 and 2007, respectively, bears interest at 7.6% per annum and matures in full in 2024 upon final payment of the related debt.

As a condition of the long-term debt due CFC (See Note 8), the Cooperative purchased Zero Term Certificates (ZTCs). One of the ZTCs, totaling $15,065 as of December 31, 2008 and 2007, is non-interest bearing and matures in 2013. New ZTCs totaling $3,572,500 purchased in 2008 bear interest at 4.36% per annum and mature in 2013.

The SCTCs, STC and ZTCs are unrated, uncollateralized debt securities of CFC.

Investment in associated organizations - The Cooperative is a Class B member of Sierra Southwest Cooperative Services, Inc. (Sierra). The Cooperative's investment in Sierra is carried at cost (See Note 17).

In December 2006, the Cooperative became an equity member of Alliance for Cooperative Energy Services Power Marketing LLC (ACES). The Cooperative's investment in ACES is accounted for under the cost method of accounting.

Patronage capital - Patronage capital represents capital credit allocation of margins due to the Cooperative. Such amounts are returned to the Cooperative in accordance with the associated organizations bylaws and/or at their discretion. Of this balance, $2.7 million represents patronage allocations from Southwest Transmission Cooperative (See Note 17).

Municipal bonds are valued based on quoted market prices for those or similar investments. The fair value of term certificates, investment in associated organizations and patronage capital is not readily determinable; therefore, they are recorded at cost.

Note 4 - Restricted Cash and Cash Equivalents

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

	2008	2007
California power sales collateral security (Note 11)	$ 2,500,000	$ 2,500,000
Rural economic development revolving loan program (Note 6)	421,109	392,976
Other deposits on account	950,285	883,724
Total restricted cash and cash equivalents	$ 3,871,394	$ 3,776,700

Note 5 - Accounts Receivable

Accounts receivable at December 31 consist of the following:

	2008	2007
Member energy sales	$ 17,717,117	$ 19,765,764
Due from related party	716,445	1,167,014
Nonmember energy sales	1,474,094	625,418
Other	753,937	52,930
Total accounts receivable	$ 20,661,593	$ 21,611,126

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.

Nonmember energy sales - Nonmember energy sales consist of nonfirm sales to unrelated electric utilities and are generally not collateralized.

Note 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, is used for providing loans to foster rural economic development. Loans made from repayments of the initial loans may carry an interest rate. As of December 31, 2008 and 2007, the Cooperative has $421,000 and $393,000, respectively, of cash and cash equivalents restricted for use in this program (See Note 4).

Note 7 - Deferred Debits

Deferred debits at December 31 consist of the following:

	2008	2007
Deferred overhaul costs	$ 7,719,209	$ 5,486,420
Unamortized debt costs	329,362	389,206
Preliminary survey and investigation and other deferred debits	1,240,375	130,705
Redemption premium (See Note 8)	175,398	193,543
Total deferred debits	$ 9,464,344	$ 6,199,874

Note 8 - Long-Term Debt

Federal Financing Bank (FFB) - Long-term debt due 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 4.2% to 9.1% for December 31, 2008 and 2007. Quarterly principal and interest installments on these obligations extend through 2034. The obligations are guaranteed by 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 and the present value of the loan discounted at a rate equal to the then current cost of funds to the Department of the Treasury for obligations of comparable maturity; 2) 100% of the amount of interest for one year on the outstanding principal balance of the loan being refinanced multiplied by the ratio of a) number of quarterly payment dates remaining to maturity bears to b) number or quarterly payment dates between year 13 of the loan and the maturity date; or 3) present value of 100% of the amount of interest for one year on the outstanding principal balance of the loan.

Cooperative Utility Trust - The Cooperative issued a note, underlying a Certificate of Beneficial Interests (the Certificate), to a Cooperative Utility Trust. Principal payments on the note are due annually through 2018 and guaranteed by RUS. The interest rate on the note is 7.7%, paid semiannually. The note may be prepaid any time after September 1, 2006 at 103.5% of the outstanding principal amount of the note on the date of prepayment, declining one half percent per year to 100% beginning September 1, 2013 and thereafter.

Note 8 - Long-Term Debt (Continued)

Solid Waste Disposal Revenue Bonds - Principal on these bonds is due in annual installments through 2024. Interest rates on the bonds are variable and subject to revision semiannually. The interest rate in effect at December 31, 2008 and 2007 was 2.35% and 3.75%, respectively. Interest is paid semiannually. These bonds are guaranteed by CFC and are not subject to optional redemption prior to maturity.

Rural Utilities Service - Long-term debt due RUS consists of notes at interest rates of 2% and 5% for 2008 and 2007. Quarterly principal and interest payments on these obligations extend through 2010. The Cooperative may prepay the notes at an amount not less than the outstanding principal balance of the loan. The discount rate is the rate specified in the Treasury Constant Maturities section of the weekly publication of the Federal Reserve Statistical Release.

RUS established a Cushion of Credit Payment Program, whereby borrowers may make advance payments on their RUS and FFB notes (Notes). These advance payments earn interest at the rate of 5.0% per annum. The advance payments, plus any accrued interest, can only be used for the payment of principal and interest on the Notes. The Cooperative's participation in the Cushion of Credit Payment Program totaled approximately $26,000 and $5,000 at December 31, 2008 and 2007, respectively, and is recorded as a reduction of RUS long-term debt on the balance sheets.

Cooperative Finance Corporation - Long-term debt due 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, 2008 and 2007 was 5.40% and 6.55%, 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 - Maturities of long-term debt for the next five years and thereafter are as follows:

2009	$ 6,645,314
2010	6,606,097
2011	7,104,889
2012	8,106,865
2013	37,302,461
Thereafter	113,424,022
	$ 179,189,648

Note 8 - Long-Term Debt (Continued)

Under covenants of the Consolidated Mortgage and Security Agreement (Mortgage), dated June 14, 1989, by and among the Cooperative, CFC and the United States of America acting through RUS, and RUS general and preloan policies and procedures, the Cooperative must, among other things, obtain approvals from both RUS and 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. Management believes these financial covenants have been achieved as of December 31, 2008.

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

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 are considered reasonable estimates of their fair value. The fair value of debt at December 31, 2008 and 2007 was $188,961,909 and $177,907,656, respectively.

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

	2008	2007
Total interest costs and related amortization	$ 11,572,860	$ 13,135,195
Interest capitalized	(179,778)	(156,371)
Total interest expense	$ 11,393,082	$ 12,978,824

Note 9 - Member Advances and Other Investments

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. The Cooperative had recorded liabilities for notes of $12,134,537 and $10,756,899 at December 31, 2008 and 2007, respectively. The interest rate on these notes averaged 2.4% and 5.2% in 2008 and 2007, respectively. Interest expense on these notes was approximately $281,000 and $441,000 for the years ended December 31, 2008 and 2007, 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 $4,127,159 and $4,539,855 at December 31, 2008 and 2007, respectively. The interest rate on these prepayments averaged 2.5% and 5.3% in 2008 and 2007, respectively. Interest expense on these prepayments was approximately $74,000 and $217,000 for the years ended December 31, 2008 and 2007, respectively.

Environmental Portfolio Standard Plan (EPS Plan) - The Arizona Corporation Commission established the Environmental Portfolio Standard requirements in 2005 to require Arizona utility companies to generate a percentage of their power through green or renewable resources. The Cooperative Class A Arizona Members collect the funds through their monthly billings and the Cooperative manages these funds on behalf of these Members. Once the Cooperative incurs expenditures related to an approved renewable resource project, Member balances are reduced by their proportionate shares of the expenditures. The balance of these funds at December 31, 2008 and 2007 was $1,582,840 and $1,927,772, respectively.

Note 10 - Deferred Credits

Customer advance payments - In 1987, the Cooperative entered into a long-term power sale agreement with a nonmember customer for an initial term of 25 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.

Note 11 - Commitments and Contingencies

Class A Member Power Sales Contracts - ***Wholesale Power Sales Contracts*** - The Cooperative holds all requirements wholesale power sales contracts with four of its six Class A Member cooperatives pursuant to which each Class A Member agrees to purchase from the Cooperative all of its electric power requirements. These all requirements power contracts expire 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 its requirements on these long-term contracts. The Cooperative has one Class A all requirements Member whose conversion to a partial requirements contract arrangement was approved by the Arizona Corporation Commission in December 2007 and was effective January 1, 2008.

Class A Member Power Sales Contracts - ***Partial Requirements Wholesale Power Agreements*** - The Cooperative holds partial requirements wholesale power sales contracts, expiring December 31, 2035, with two of its Class A Member cooperatives pursuant to which the Class A Members have agreed to purchase from the Cooperative electric energy and capacity up to the Member's allocated capacity percentage in the Cooperative's total resources existing at the time of execution of the contract. The Cooperative has one Class A Member whose conversion to a partial requirements contract arrangement was approved by the Arizona Corporation Commission in December 2007 and was effective January 1, 2008.

Class B and Class C Member Power Sales Contracts - The power sales contract with the Cooperative's Class B Member, for the sale of 15 MW of capacity, expired on December 31, 2008. The power sales contract with the Cooperative's Class B Member, for the sale of 100 MW of capacity, expires on December 31, 2010. There are no Class C Member contracts at this time.

Class D Member Power Sales Contract - Class D membership requires the Member to enter into a service contract for scheduling and trading services for a minimum term of 2 years. The service contract with the Cooperative's Class D Member is renewed annually until terminated by either party upon a six month written notice.

Nonmember Power Sales Agreement - Nonmember power sales agreement consists of the following:

- 8 MW agreement expiring on December 31, 2012.

Note 11 - Commitments and Contingencies (Continued)

Wholesale Power Purchase Contracts - The Cooperative's current power supply includes the following purchase power agreements:

- 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, 2024, the Cooperative can receive up to 2.4 MW during October through March and up to 12.5 MW during April through September for service to its Class A Members. Additionally, under the terms of a contract with the Parker Davis Project, which expires September 30, 2028, the Cooperative receives 18.4 MW during October through February and 23.8 MW during March through September.
- Power purchase agreement with the Public Service Company of New Mexico, expired on December 31, 2008, to purchase capacity of 15 MW.
- Power purchase agreement with South Point Energy Center to purchase capacity in Peak Hours ranging from 30 MW to 55 MW during the months of May through October for the term of the agreement which began on May 1, 2008 and expires October 31, 2014.
- Power purchase agreement with Griffith Energy, LLC, a Dynegy subsidiary, to purchase capacity in Peak Hours of 25 MW during the months of May through October for the term of the agreement which began on May 1, 2008 and expires October 31, 2014.
- Power purchase agreement with Powerex Corp to purchase energy in Peak Hours of 25 MW during the months of June, July and August 2007 and 2008, and 35 MW during the same months of 2009 and 2010.

Network Service Agreement (Class A) - The Cooperative holds an agreement with Southwest Transmission Cooperative, Inc. (SWTC) for network integration transmission service for delivery of its power sales to the Cooperative's 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 all requirements Class A members remains in effect (See Note 17).

Bundled Transmission Service Agreements - The Cooperative holds agreements with SWTC for point-to-point transmission for the Cooperative'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 power sale agreement (See Note 17).

Wholesale Transmission Contracts - The Cooperative holds separate agreements by which it takes transmission services from other entities ranging from 35 MW to 50 MW, which will remain in effect in accordance with each respective service agreement. The Cooperative uses certain of these agreements to be able to take power from certain of its power purchase agreements and the wholesale power market. In the opinion of management, the Cooperative will be able to use these contracts to provide service to the Class A all requirements members in accordance with these agreements.

Note 11 - Commitments and Contingencies (Continued)

Rate Filing Application - On August 7, 2005, the ACC approved the Cooperative's application for a rate increase to be implemented over a two-year period (the Order). Phase one became effective September 1, 2005 and resulted in a 12.44% increase; phase two became effective September 1, 2006 and resulted in a 1.5% increase; phase three became effective September 1, 2007 and resulted in a 1.5% increase. As discussed in Note 2 (Revenues, purchased power and fuel costs), the Order approved a fuel and purchased power cost adjustor. The Order also approved a demand side management (DSM) adjustor in the anticipation of the adoption of DSM rules by the ACC and the potential that the Cooperative may engage in DSM programs. The DSM adjustor would allow the Cooperative to recover the cost of the DSM programs. The Cooperative will be filing a new rate application with ACC in 2009.

California Power Sales - ***Collateral Security*** - When the Cooperative entered into scheduling coordinator agreements with the California Independent System Operator (ISO) and the California Power Exchange (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, totaling $3,500,000. Pursuant to a November 2008 FERC order, the letters of credit were released in January 2009.

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.

California Power Sales - ***California Refunds*** - In response to complaints about sharp price increases for wholesale electricity sold in single price auction markets operated by the ISO and the CPX, the FERC opened an investigation under section 206 of the Federal Power Act (FPA) to determine whether rates in those markets were just and reasonable. It determined under FPA section 206(b) that excessive rates charged in those markets between October 2, 2000 and June 20, 2001 (regular refund period) would have to be refunded. The Cooperative stopped selling into the California markets in early January 2001. On July 25, 2001, the FERC ruled that all sellers in the ISO and CPX markets, including government utilities and the Cooperative, the only electric cooperative involved, who are otherwise exempt from its regulatory jurisdiction, would also have to make refunds. Government entities and the Cooperative appealed the FERC's decision to the 9th Circuit Court of Appeals, who ruled on September 6, 2005, in Bonneville Power Administration v. FERC, that FERC does not have jurisdiction over wholesale energy sales made by government entities and by non-public utilities. This decision is now final.

Note 11 - Commitments and Contingencies (Continued)

Following the jurisdictional ruling in the 9th Circuit Court of Appeals, some California investor-owned utilities and the California Electricity Oversight Board (California Parties) filed lawsuits in March 2006 in federal district court against the non-jurisdictional entities including the Cooperative. These suits were dismissed for lack of federal jurisdiction, and refiled in California State court, in the complex case division of the county of Los Angeles. This case was thereafter dismissed as to AEPCO, without prejudice. This dismissal is being appealed. The suits seek refunds for sales to the ISO and CPX between May 1, 2000 and October 1, 2000 (early refund period) and October 2, 2000 and June 20, 2001 (regular refund period). Using the methodology accepted by FERC for calculating the refund liabilities of the participant sellers, the estimate of the Cooperative's liability, related to the regular refund period, would be approximately $9,000,000, less unpaid accounts receivable of approximately $2,500,000 resulting from the Cooperative's participation in the California market as a participant seller, and other miscellaneous allowances and interest. The Cooperative is unable to develop an estimate for the amount of the refunds that might be due for the early refund period. The Cooperative, based on the progress of the litigation, is unable to determine whether the likelihood of an unfavorable outcome is either probable or remote and has not recorded a contingent liability. The Cooperative disagrees with the basis of the claims and intends to vigorously contest this litigation.

Fuel Procurement Contracts - ***Coal Supply Agreements*** - To ensure an adequate fuel supply, the Cooperative enters into various long-term fuel contracts. At December 31, 2008, these contracts consist of:

- A 36-month contract, effective January 1, 2009. The terms of the contract require the Cooperative to purchase a minimum of 1,100,000 tons during each year of the contract.
- A 12-month contract, effective January 1, 2009. The terms of the contact require the Cooperative to purchase a minimum of 250,000 tons.
- A 12-month contract, effective January 1, 2009. The terms of the contract require the Cooperative to purchase 200,000 tons. However, the Cooperative has resold part of the contract quantity, and will also likely resale the remaining tons.

Rail Transportation Agreement - The Cooperative's rail transportation contracts expired on December 31, 2008. 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 2008 filed a complaint with the Surface Transportation Board (STB) seeking the establishment of reasonable rates and other terms for unit train coal transportation service.

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).

Note 11 - Commitments and Contingencies (Continued)

Coal Railcar Maintenance Agreement - The Cooperative entered into a 10-year railcar maintenance service agreement, effective December 17, 2002, for the maintenance of the coal railcar trainset leased under the 20-year lease agreement (See Note 15 - Coal Railcar Trainsets). The agreement shall continue for successive 12-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 17). 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. Neither the Cooperative nor Sierra gave the two-year advance notice of termination, thereby extending the agreement for an additional five-year term.

Approximately 43% of the personnel employed by Sierra are subject to a collective bargaining agreement. Sierra entered into a five-year collective bargaining agreement, effective March 1, 2005.

Office Facilities and Machinery and Equipment Lease Agreements - The Cooperative has entered into lease agreements with Sierra and SWTC, whereby Sierra and SWTC lease the Cooperative's office facilities and substantially all of its nongenerating machinery and equipment (See Notes 15 and 17).

Natural Gas Sales Agreement - The Cooperative has entered into an agreement with Sierra for the purchase or sale of natural gas at the then prevailing market price for natural gas. The transactions under the agreement are intended to be mutually beneficial to both parties, whereby the supply of natural gas of one party in excesses of its current demand can be sold to the other party to enable it to better match its demand. The agreement became effective March 17, 2003 and continues in effect until terminated by either party upon 30 days written notice (See Note 17).

Letters of Credit - Letters of credit issued by CFC in the amounts of $1,653,750, $2,000,000 and $2,043,101, were obtained by the Cooperative for the purpose of providing credit support for a power purchase agreement with Griffith Energy LLC, providing credit support for a power purchase agreement with Powerex Corporation and for a five-year lease with Marquette Equipment Financing, respectively. The letter of credit issued to Griffith Energy LLC is subject to annual renewals with the last expiration date not extending past January 31, 2015. The letter of credit issued to Powerex Corporation is subject to annual renewals with the last expiration date not extending past September 30, 2010. The Marquette

Note 11 - Commitments and Contingencies (Continued)

Equipment Financing letter of credit was issued on June 5, 2008 with an expiration date of March 31, 2012. The interest rate if draws were to occur will be equal to a fixed rate set by CFC, not to exceed the "Prevailing Bank Prime Rate", as published in the "Money Rates" column of the Wall Street Journal, plus one percent per annum. As a condition of the letters of credit, the Cooperative is required to remain in compliance with the terms and conditions of the Consolidated Mortgage and Security Agreement (See Note 8).

Lines of Credit - The Cooperative maintains a line of credit with CFC maturing March 2, 2011. As of December 31, 2008, the line of credit was for $25,000,000. The interest rate on advances is 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 in the "Money Rates" column of The Wall Street Journal, plus one percent per annum. The bank prime rate at December 31, 2008 was 3.25%.

The Cooperative also maintains a line of credit agreement with CFC for $250,000 as part of its credit card program. The agreement remains in effect until terminated by either party with a 90-day notice. No amounts were drawn under this line of credit for the years ended December 31, 2008 and 2007.

Capital Lease - Capital lease property and the related liabilities are in substance asset purchases. Assets and liabilities under capital leases are recorded at the lesser of the present value of the minimum lease payments or the fair value of the assets. The assets are amortized over their related lease terms or their estimated useful lives, whichever is less. On December 22, 2005, the Cooperative entered into a master lease agreement to finance the purchase and installation of an enterprise resource planning software (ERP) system. To finance additional upgrades and enhance features of the ERP system as well as to take advantage of improved lease rates, the Cooperative incorporated the initial lease schedules with additional funding into a new lease schedule dated June 4, 2008. The initial period of the lease is twenty (20) quarters starting April 1, 2009. Future minimum lease payments are as follows:

2009	$ 1,621,421
2010	1,621,421
2011	1,621,421
2012	1,445,395
2013	795,601
Total minimum lease payments	7,105,259
Less amount representing interest	1,193,020
Present value of minimum lease payments	5,912,239
Less current portion	1,260,950
	$ 4,651,289

Note 12 - Patronage Capital

Patronage Capital Allocation - In accordance with the Cooperative's bylaws, net margins are accounted for on a patronage basis in the following sequence:

- Offset prior year's unallocated accumulated losses.
- 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% of the margins received by the Cooperative in the preceding year, unless total membership capital exceeds 40% of the total assets of the Cooperative. There were no retirements for 2008 and 2007.

Note 13 - Income Tax Status

The Cooperative is exempt from income taxes under the provisions of Section 501(c)(12) of the Internal Revenue Code. Pursuant to FSP FIN 48-3, management has elected to defer the application of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, to fiscal years beginning after December 15, 2008. For the years ended December 31, 2008 and 2007 the Cooperative has accounted for uncertain tax positions in accordance with FASB Statement No. 5, Accounting for Contingencies, whereby the effect of the uncertainty would be recorded if the outcome was considered probable and was reasonably estimatable. As of December 31, 2008 and 2007, the Cooperative has no provision for income taxes.

Note 14 - Retirement Plans

The Cooperative has a defined benefit pension plan covering substantially all of its employees. Pension benefits 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 NRECA. Contributions made to this plan approximated $277,000 and $208,000 for the years ended December 31, 2008 and 2007, respectively. The Cooperative's policy has been to fund retirement costs annually as they accrue.

This multi-employer plan is available to all member cooperatives of NRECA. Information concerning the Cooperative's proportionate share of the excess, if any, of the actuarially computed value of vested benefits over the pension plan's net assets is not available from NRECA; the plan administrator.

The Cooperative also offers participation in the NRECA SelectRE Pension Plan to all employees meeting certain minimum service requirements. This plan has 401(k) salary deferral features. Under this plan, the Cooperative matches a percentage of the employees' contributions to the plan. The Cooperative's contributions to the plan were approximately $58,000 and $52,000 for the years ended December 31, 2008 and 2007, respectively.

Note 15 - Operating Leases

Commercial office building - In 1999, the Cooperative entered into a noncancelable lease agreement for the lease of a commercial office building (office lease). The initial lease term is for a period of ten years with a renewal option to extend the term of the lease for an additional five years. The Cooperative has subleased the building to Sierra and other tenants. The term of the lease with Sierra is for 89.5 months and commenced on August 1, 2001. Rent expense for the lease of the commercial office building was approximately $217,000 and $216,000 for the years ended December 31, 2008 and 2007, respectively, and is included in administration and general on the accompanying statements of revenues and expenses and unallocated accumulated margins. Rental income received from the sublease of the commercial office building was approximately $112,000 and $251,000 for 2008 and 2007, respectively. In 2008, the Cooperative did not renew the agreement and terminated the lease January 14, 2009.

Computer equipment - The Cooperative entered into master lease agreements for the lease of substantially all the Cooperative's personal computers and peripheral equipment. Individual certificates of acceptance (COAs), underlying the master lease agreements, are entered into as groups of computers and equipment are delivered. The terms of the COAs are for up to four years. Rent expense for the lease of the computer equipment was approximately $401,000 and $466,000 for the years ended December 31, 2008 and 2007, respectively, and is included in administration and general on the accompanying statements of revenues and expenses and unallocated accumulated margins.

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. At December 31, 2008, these lease agreements consist of:

- A 20-year lease agreement, effective December 17, 2002. Lease payments under this agreement totaled approximately $400,000 in 2008 and 2007. 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 60-month lease agreement, effective January 1, 2004. Lease payments under this agreement totaled approximately $522,000 and $569,000 for 2008 and 2007, respectively.
- A 72-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 $62,000 and $140,000 for 2008 and 2007, respectively.
- A 36-month lease agreement, effective August 1, 2006. This lease provides for the use of coal railcars. Lease payments under this agreement totaled approximately $1,175,500 and $1,180,500 for 2008 and 2007, respectively.

Note 15 - Operating Leases (Continued)

The following summarizes the future minimum lease payments under operating leases that had initial or remaining lease terms in excess of one year at December 31, 2008:

2009	$ 1,088,225
2010	399,600
2011	399,600
2012	399,600
2013	399,600
Thereafter	3,596,400
	$ 6,283,025

Note 16 - Concentration of Customers and Credit Risk

Revenue and accounts receivable for the year ended December 31, 2008 included amounts from four customers, whom each individually represented more than 10% of the total operating revenue and accounts receivable. Revenue from these customers collectively represented approximately 83% of total operating revenue for 2008. The amounts owed from these customers collectively represented approximately 83% of the total accounts receivable balance at December 31, 2008.

Revenue and accounts receivable for the year ended December 31, 2007 included amounts from four customers, whom each individually represented more than 10% of the total operating revenue and accounts receivable. Revenue from these customers collectively represented approximately 85% of total operating revenue for 2007. The amounts owed from these customers collectively represented approximately 84% of the total accounts receivable balance at December 31, 2007.

Note 17 - Related Parties

The Cooperative is a Class B member of Sierra and SWTC. Class B members of Sierra are collectively represented by one director seated on Sierra's board of directors. Class B members of SWTC are also collectively represented by one director seated on SWTC's board of directors. Directors for both SWTC and Sierra are entitled to one vote on each matter submitted to a vote at a meeting of the members. The Cooperative's investment in Sierra was $3,000,000 as of December 31, 2008 and 2007 and is carried at cost. The Cooperative's patronage allocation from SWTC was approximately $2,700,000 at December 31, 2008 and 2007.

Note 17 - Related Parties (Continued)

The Cooperative has entered into an agreement with Sierra, whereby Sierra provides personnel staffing services (See Note 11 - Personnel Staffing Agreement). For 2008 and 2007, the Cooperative recorded expenses for personnel staffing services from Sierra totaling approximately $22,197,000 and $20,193,000, respectively.

The Cooperative has entered into lease agreements with SWTC and Sierra for the lease of office facilities and machinery and equipment (See Note 11 - Office Facilities and Machinery and Equipment Lease Agreements). For 2008, rents received by the Cooperative from SWTC and Sierra totaled approximately $909,000 and $1,416,000, respectively. For 2007, rents received by the Cooperative from SWTC and Sierra totaled approximately $832,000 and $1,311,000, respectively.

The Cooperative has entered into agreements with SWTC for transmission service (See Note 11 - Network Service Agreement (Class A) and Bundled Transmission Service Agreements). For 2008 and 2007, the Cooperative recorded transmission expenses from these agreements totaling approximately $14,386,000 and $19,805,000, respectively.

The Cooperative has entered into an agreement with Sierra for the sale of natural gas (See Note 11 - Natural Gas Sales Agreement). No revenues were recorded under this agreement for 2008 and 2007.

As of December 31, 2008, the Cooperative has recorded accounts payable to SWTC and Sierra totaling approximately $5,845,000 and $20,693,000, respectively, and accounts receivable from SWTC and Sierra totaling approximately $5,512,000 and $21,742,000, respectively. As of December 31, 2007, the Cooperative had recorded accounts payable to SWTC and Sierra totaling approximately $2,038,000 and $0, respectively, and accounts receivable from SWTC and Sierra totaling approximately $1,496,000 and $1,709,000, respectively. The net receivable for 2008 and 2007 are included in the accompanying balance sheets in accounts receivable.

Note 18 - Asset Retirement Obligations

The asset retirement obligation related to generation assets at December 31 consists of the following:

	2008	2007
Liability at January 1	$ 1,439,346	$ 2,447,767
Accretion expense	95,185	89,290
Reduction in estimate	-	(1,210,453)
Liabilities incurred	120,181	112,742
Liability at December 31	$ 1,654,712	$ 1,439,346

EXHIBIT
A-3
ADMITTED

SUPPLEMENTAL 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 1000 S. Highway 80, Benson, Arizona 85602.

Q. Are you the same Gary Pierson who filed direct testimony and exhibits on October 1, 2009 ("Direct Testimony") in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Supplemental Direct Testimony?

A. I am testifying in support of AEPCO's revised request for rate relief. My testimony is primarily directed to the Amended and Restated Schedules A-F which are being filed in support of the revised request. Mr. Goble provides supplemental testimony supporting Amended and Restated Schedules G and H. Collectively, the Schedules A-H being filed with this testimony are referred to as the Amended and Restated Schedules. They replace the schedules which were filed in this docket on October 1, 2009.

Q. Please describe the reason why AEPCO is revising its request for rate relief.

A. As discussed at pages 4-5 of Mr. Minson's direct testimony, in September of last year, AEPCO's Board of Directors approved the filing of a rate application which

requested an overall increase in AEPCO's annual revenues of approximately $4 million and represented a 2.41% increase in test year operating revenues on an adjusted basis. AEPCO timely filed that application on October 1, 2009 in compliance with the three-month filing deadline extension granted in Decision No. 71112. The application also reflected the progress and consensus which the Class A Members had been able to make on certain rate and rate design issues to that point. Following the filing, the member committee, which is comprised of representatives of AEPCO's Class A Members ("Member Rates Committee") and AEPCO Staff, continued work on remaining issues. In mid-March, the Member Rates Committee and AEPCO reached agreement on all remaining issues and on April 14, 2010, AEPCO's Board authorized this revised rate request. In summary, the revised request results in an overall decrease in AEPCO's annual revenues of approximately $97,000 or a 0.06% decrease in test year operating revenues.

Q. Please summarize the changes the Member Rates Committee recommended and the AEPCO Board has approved for the Amended Application.

A. There are five primary revision areas in the original October 1, 2009 application as agreed to by the Member Rates Committee and AEPCO Board:

1. The allocation of certain Resource Planning Costs is being increased to the All-Requirements Members ("ARMs");
2. The allocation method of Scheduling and Trading Revenues is being changed in relation to the Class A Members;

3. AEPCO's requested margin level is being decreased;
4. The Mercury Control Chemicals adjustment which was included in the October 1, 2009 filing is being withdrawn; and
5. The ARMs' demand rate structure is being changed from a per kW rate to a monthly fixed charge and a monthly O&M charge. In addition, the proposed energy charge for additional resources is being combined with the other existing resources energy rate.

Q. Please discuss the change in the allocation of certain Resource Planning costs to the ARMs.

A. A part of the Resource Planning Department costs which relate to future planning for the ARMs is now being assigned directly to the ARMs rather than allocating these costs on the basis of the members' Allocated Capacity Percentages ("ACP") – the method used in the original filing. This change moves about $220,000 in costs to the ARMs and decreases that same amount of costs assigned to the Partial-Requirements Members ("PRMs"). AEPCO revenue requirements, however, are not affected by this allocation change.

Q. Please discuss the change in the allocation method of Scheduling and Trading Revenues to the Class A Members.

A. In the original filing, all Scheduling and Trading Revenues were directly assigned to the ARMs. The Member Rates Committee concluded that these revenues should instead be allocated between the ARMs and PRMs on the basis of the

member's ACP. This change increases the ARMs' costs by approximately $460,000 and decreases PRM costs by the same amount. The net effect on AEPCO revenue requirements is zero.

Q. Please discuss the reduction in the proposed margin requirement level.

A. In the original filing, AEPCO proposed a margin level which would have been sufficient to result in a Debt Service Coverage Ratio of 1.35. After discussions with the Member Rates Committee, AEPCO is reducing that request to a margin level sufficient to result in a Debt Service Coverage Ratio of 1.275. The effect is to lower the AEPCO revenue requirements request by about $1.3 million.

Q. Why has AEPCO withdrawn the Mercury Control Chemicals Adjustment which was included in the October 1, 2009 filing?

A. The original filing included a $2.8 million adjustment for the cost of mercury control chemicals in order to meet the requirements of an agreement concerning mercury emissions with the Arizona Department of Environmental Quality which control strategy must start January 1, 2011. The $2.8 million adjustment was based upon proposals and treatment parameters received from potential suppliers in proposals submitted prior to the filing. Subsequently, however, AEPCO Staff has determined that the annual costs of the chemicals will be less due to changes in volume, price and patent payment factors. As a result, current cost estimates range from approximately $600,000 to $2,000,000 annually and, given this cost range, AEPCO no longer feels confident about proposing this as an adjustment.

We also determined that the chemicals will be applied to the coal as it is conveyed from the stockpile to the bunker and it is, therefore, a coal-related fuel cost in RUS Account 501 rather than a steam expense in RUS Account 502. For these reasons, we are removing the mercury control chemicals adjustment from the filing. AEPCO will instead recover these costs when incurred as allowable RUS Account 501 costs in its PPFAC. The effect of removing this adjustment reduces the AEPCO revenue requirements request by approximately $2.8 million.

Q. What conclusions did the Member Rates Committee reach concerning the ARMs' demand rate structure?

A. Currently and as proposed in our October filing, the ARMs pay a demand rate on a per kilowatt monthly basis. The ARMs instead want to shift that to a monthly fixed charge and a monthly O&M charge. As a result, we are proposing that revised demand rate structure for the ARMs. These monthly charges will be apportioned between the ARMs based upon each ARM's monthly Demand Share Ratio. The Demand Share Ratio will be calculated each month as the percentage of the ARM's 12-month rolling average demand to the total of the ARMs' 12-month rolling average demand.

Q. Finally, Mr. Pierson, is there any other post-October 1, 2009 development which may impact AEPCO rates?

A. Yes. Several weeks after the filing, in November, Trico served notice that it was electing its right to convert to partial-requirements service pursuant to the

1 Conversion Agreement dated August 1, 2001 between AEPCO and its Class A
2 Members. The partial-requirements conversion process requires the preparation
3 of a Partial Requirements Capacity and Energy Agreement along with other
4 agreements that must be approved by this Commission and the Administrator of
5 the Rural Utilities Service ("RUS"). The drafting of those agreements is
6 underway and it is expected they will be filed for Commission and RUS approval
7 in the next several weeks. However, because the agreements have not yet been
8 finalized, executed, filed and approved, AEPCO has made this amended filing on
9 the basis of Trico's current status as an ARM. When AEPCO and its members
10 jointly submit those agreements for approval, we will also provide recommended
11 rates for Trico as a PRM.
12
13 **Q. Please describe the Amended and Restated Schedules.**
14 A. They follow the same format as the originally filed Schedules A-H. For
15 convenience, we have restated all of the schedules in an integrated package which
16 contains amendments to schedules impacted by the five revision areas I discussed
17 previously. I will discuss only those schedules which have been changed.
18
19 **Q. Please describe Section A of the Amended and Restated Schedules.**
20 A. Section A contains the rate filing's summary schedules. Schedule A-1 shows the
21 proposed revenue decrease of approximately $97,000 is a slight decrease of
22 0.06% in the revenues generated by present rates on an adjusted basis. Based
23 upon a test period adjusted rate base of $231.8 million, the revised revenues

generate a rate of return of 6.06%. Among other things, Schedule A-2 summarizes results of operations for the adjusted test year with present rates and with proposed rates. The Test Year Adjusted column shows that AEPCO had a net margin of approximately $3.33 million, a TIER of 1.31 and a DSC of 1.28. Under the revised proposal, AEPCO's net margin drops to about $3.24 million; its TIER is 1.30; and its DSC is 1.275. Schedule A-3 margins and equity and capitalization for the projected year end change as a result of the revisions discussed previously, as does the Schedule A-5 net cash provided by operating activities for the present and proposed rates.

Q. Are there any changes to the B Schedules as a result of the revisions to the rate request?

A. No, there are not.

Q. Please describe what changes have been made to the C Schedules as a result of the revised request.

A. Generally, only two changes have been made to the C Schedules and they relate to the removal of the mercury control chemicals adjustment which I discussed previously. Referring to pages 7 and 8 of Schedule C-2, the $2,804,076 entries in column 11 labeled "Mercury Control Adjustment" have been removed. Then, as indicated on Schedule C-2, page 10, the total of the remaining adjustments to expenses and revenues result in a decrease in net margins of $12.5 million.

1 **Q. Please describe Section D of the Amended and Restated Schedules.**

2 A. The D Schedules contain information on AEPCO's cost of capital for the
3 12 months ended March 31, 2007, 2008 and 2009 and the projected 12 months
4 ended March 31, 2010. They were not affected by any of these changes to the
5 rate request.

6

7 **Q. Are any of the E Schedules impacted by the revised request?**

8 A. No. They have simply been restated as originally filed.

9

10 **Q. Finally, what changes have been made to the F Schedules in the Amended and**
11 **Restated Schedules?**

12 A. Schedule F-1's Adj. Test Year-Present Rates column changes because of the
13 removal of the mercury control chemical adjustment. Its Net Income (Margins)
14 entry at line 56 changes to $3.3 million. Also, as a result of the change in the
15 requested margin level and the removal of the mercury control chemical adjustment,
16 Net Income (Margins) changes to $3.2 million in the Proposed Rates column.
17 Schedule F-2's Net Cash Provided By Operating Activities also changes for the
18 Projected Year Present Rates and Proposed Rates columns as a result of these
19 revisions.

20

Q. Mr. Pierson, please summarize the revised rates AEPCO requests the Commission approve.

A. The following is a summary of the present and the revised proposed rate structures:

	Present Rates	Proposed Rates
All-Requirements Members:		
Demand Rate	$14.98/kW Month	
Fixed Charge		$862,343/Month
O&M Charge		$1,229,653/Month
Energy Rates:		
Base Resources		$0.03236/kWh
Other Existing Resources		$0.06746/kWh
Energy Rate	$0.02073/kWh	$0.03722/kWh (Average)
Partial-Requirements Members:		
Mohave Electric Cooperative:		
Fixed Charge	$855,113/Month	$709,721/Month
O&M Charge	$7.26/kW Month	$1,323,724/Month
Energy Rates:		
Base Resources		$0.03216/kWh
Other Existing Resources		$0.06879/kWh
Energy Rate	$0.02073/kWh	$0.03595/kWh (Average)

<u>Sulphur Springs Valley Electric Cooperative</u>:

Fixed Charge	$757,429/Month	$628,440/Month
O&M Charge	$7.26/kW Month	$1,172,125/Month
Energy Rates:		
Base Resources		$0.03230/kWh
Other Existing Resources		$0.06676/kWh
Energy Rate	$0.02073/kWh	$0.03672/kWh (Average)

The Fixed Charge and the O&M Charge for the ARMs will be billed to each ARM according to its demand share ratio based upon the percentage of its rolling 12-month average demand to the total of the ARMs' rolling 12-month average demand.

Q. Are there any proposed revisions to PPFAC requested?

A. Yes. AEPCO proposes that the ARM PPFAC power cost base for the Additional ARM Resources pool originally proposed as a separate rate instead be combined with the Other Existing Resources pool. Mr. Goble testifies about this proposal in more detail in his Supplemental Direct Testimony.

Q. Does this conclude your supplemental direct testimony?

A. Yes, it does.

EXHIBIT
A-4
ADMITTED

REBUTTAL TESTIMONY OF

GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

August 30, 2010

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1 **REBUTTAL TESTIMONY OF GARY E. PIERSON**

2 **ON BEHALF OF**

3 **ARIZONA ELECTRIC POWER COOPERATIVE, INC.**

4 **Q. Mr. Pierson, are you the same Gary E. Pierson who sponsored Direct and**
5 **Supplemental Direct Testimonies for Arizona Electric Power Cooperative, Inc.**
6 **("AEPCO") in this matter?**

7 A. Yes, I am.

8 **Q. Have you reviewed the Direct Testimonies of Staff witnesses Messrs. Smith, Vickroy**
9 **and Antonuk which were filed in this matter?**

10 A. Yes, I have. My Rebuttal Testimony provides AEPCO's responses to issues raised in
11 each of their testimonies. Mr. Goble's Rebuttal Testimony presents revised Schedules G
12 and H and revised recommended rates in support of and consistent with AEPCO's
13 rebuttal positions.

14 **RATE BASE—AEPCO REBUTTAL POSITION**

15 **Q. Have you reviewed Staff's testimony on original cost rate base and the determination**
16 **of fair value for this proceeding?**

17 A. Yes, I have. AEPCO accepts each of the rate base adjustments proposed by Mr. Smith at
18 pages 16-22 of his testimony. Therefore, we accept Staff's proposed rate base of $211.8
19 million—as set forth in Mr. Smith's Attachment RCS-2, page 4—as the fair value rate base.

OPERATING INCOME—AEPCO REBUTTAL POSITION

Q. What is the rebuttal position of AEPCO regarding operating income?

A. While AEPCO does not necessarily agree with all of the adjustments to revenue requirements offered by Mr. Smith, in order to narrow disputed issues and reduce complexity, AEPCO accepts all five of the adjustments to operating income discussed at pages 24-26 of his testimony. As a result, AEPCO accepts Staff's Test Year Adjusted revenues of approximately $178.8 million, operating expenses of $162.8 million, electric operating income (margins) of $15.9 million and net margins in the test year of $5.2 million as set forth on Attachment RCS-2, Page 2, Column D.

Q. At pages 27-28 of his Direct Testimony, Mr. Smith accepted AEPCO's annual rate case expense amount of $160,000 "pending receipt of additional detail." Please update AEPCO's rate case expense.

A. As our response to STF 1.52 indicated, based on the legal fees and costs incurred in AEPCO's 2004-2005 rate case, plus a projection of this case's consultant fees and costs, we estimated that rate case expenses would amount to $480,000. Correspondingly, we requested an annual expense allowance of $160,000, i.e., the $480,000 estimate divided by a three-year recovery period. Through July 2010, total rate case expenses have already exceeded that estimate and are just over $541,000.

1 **Q. Mr. Pierson, has the AEPCO rate case been more complicated and required more**
2 **consulting and legal support than SWTC's?**
3 A. Yes. We expected it would be more complicated and that has certainly been the case. In
4 fact, in some respects, the AEPCO case has actually been two rate cases—(1) the original
5 application with prepared testimony and schedules filed in October 2009 and (2) the
6 Amended Application, supporting testimony and amended and restated schedules filed on
7 April 20, 2010. AEPCO also prepared and filed the Request and the Joint Request for
8 Approval of the Contract/Amendments and revised rates on June 2, 2010. None of these
9 additional filings were necessary in the SWTC rate case. The AEPCO rate case also has
10 presented several complexities and issues which are not involved in the SWTC filing,
11 such as the new AEPCO rate design, the revised Purchased Power and Fuel Adjustment
12 Clause ("PPFAC") and the Liberty Consulting Group's prudence review. Finally,
13 another indication of the higher complexity of the AEPCO case has been the amount of
14 discovery each case has required to date. So far, we have responded to about 140 Staff
15 data requests in the SWTC case. However, responses in the AEPCO rate case have been
16 more than double that figure—12 sets of data requests requiring 314 responses. All of
17 these factors have contributed to higher legal and consulting costs on the AEPCO case.

COST OF CAPITAL—AEPCO REBUTTAL POSITION

Q. What is AEPCO's position on Mr. Vickroy's debt service coverage ("DSC") recommendation of 1.40?[1]

A. Mr. Vickroy recommends a 1.40 DSC because he is concerned that AEPCO's 1.275 DSC request is "too thin from both a net margin and cash flow perspective."[2] As I discussed at page 4 of my Supplemental Direct Testimony, AEPCO's lower DSC request of 1.275 was the result of discussions and an agreement with the Member Rates Committee (the "Committee") prior to filing the Amended Application. After reviewing Mr. Vickroy's testimony, AEPCO met several times telephonically with the Committee to determine if the 1.275 DSC position should be amended. After consideration of Mr. Vickroy's analysis and as a result of those discussions with the Committee, AEPCO's Management recommended and AEPCO's Board authorized setting our request for margin requirements at a 1.32 DSC rather than our prior position of 1.275. AEPCO believes this DSC request will provide adequate revenues and margins based on adjusted test year results. That is our position on rebuttal and results in a revised operating margin request of approximately $2.95 million as compared to Staff's $4.35 million.

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[1] Vickroy Direct, p. 18, ll. 4-5.
[2] *Id.*, p. 16, l. 23.

1 **REVENUE REQUIREMENTS—AEPCO REBUTTAL POSITION**

2 **Q. Mr. Pierson, have you prepared an exhibit which summarizes AEPCO's current**
3 **positions and requests regarding revenue requirements?**

4 A. Yes, I have. Exhibit GEP-2 summarizes AEPCO's amended rate filing, Staff's Direct
5 Testimony and AEPCO's rebuttal positions. As shown on Exhibit GEP-2, Column 3,
6 AEPCO has reduced its rate request on rebuttal from the 0.06% revenue decrease
7 presented in our Amended Application to a 0.70% decrease over test year present rates
8 based upon the revised requested DSC of 1.32. The rate of return on the rate base of
9 $211.8 million is 6.97%.

10 **PRUDENCE REVIEW—AEPCO REBUTTAL POSITION**

11 **Q. Have you reviewed the Direct Testimony of Staff witness Mr. Antonuk concerning the**
12 **Prudence Review which was filed on July 30, 2010 in this matter?**

13 A. Yes, I have. AEPCO appreciates the comprehensive Prudence Review which was
14 conducted by Liberty Consulting Group ("Liberty") on behalf of Staff. Mr. Antonuk's
15 testimony and the detailed report (Exhibit JEA-2) were immediately distributed to and
16 have been thoroughly reviewed by AEPCO's management and the personnel involved in
17 the subject matters covered by the report. It was also provided to AEPCO's Board of
18 Directors and was discussed with the Board at its August meeting. AEPCO has also sent
19 copies of the public version of the Prudence Review to the Rural Utilities Service and
20 National Rural Utilities Cooperative Finance Corporation. Finally, it has also been made
21 available to all of AEPCO's employees through our website.

1 **Q. How have you organized AEPCO's response to Mr. Antonuk's testimony?**

2 A. Having met with the key personnel involved in each of the seven subject areas reviewed
3 by Liberty, I'll first summarize our understanding of the primary conclusions reached in
4 each area. I will then provide AEPCO's response to Liberty's concerns and
5 recommendations. My response is based on my discussions with AEPCO's management
6 and employees in each of the operational areas.

7 **Q. Please proceed.**

8 A. As an initial matter, we certainly agree with most of Liberty's conclusions. Specifically,
9 AEPCO agrees with the following conclusions which are summarized by Mr. Antonuk in
10 his Direct Testimony:

11 • Organization, Staffing and Controls (page 4) – (1) "AEPCO's fuel and
12 energy management division is organized appropriately and it includes capable
13 individuals [who]...operate under appropriate job descriptions"; (2) an "appropriate set of
14 procedures, policies, guidelines, approval authorities, and trading controls address
15 technical and ethical performance"; and (3) "AEPCO has made effective use of ACES
16 Power Marketing to provide a range of capabilities and services that are generally
17 difficult for relatively smaller organizations to replicate."

18 • Fuel Contracting (pages 4-5) – (1) "AEPCO's fuel procurement has been
19 supported by reasonable consumption forecasts"; (2) "procurements have considered an
20 appropriate range of alternatives, included proper analysis of those alternatives, properly
21 considered the potential for significant changes in freight rates, and produced sufficient
22 justification and approval documentation"; (3) "AEPCO has pursued coal resales and

swaps, which have produced savings for members, permitted [the] opportunity for testing new sources of supply, and mitigated the effects of increased rail costs"; (4) "AEPCO has also taken appropriate action to contest proposed increases in rail transportation rates from the Union Pacific"; and (5) "AEPCO has also appropriately developed, and is properly maintaining its gas-supply relationships."

- Fuel Supply Management (pages 6-7) – (1) "AEPCO applies appropriate processes and procedures for the weighing, sampling, and analysis of coal shipments to Apache"; (2) "AEPCO has effectively administered its coal contracts to assure quantity and quality control, while appropriately maintaining effective supplier relationships"; (3) AEPCO's decision "to increase certain coal inventories, in order to address the prospect of substantially increased coal transportation rates...was effective [and] supported...with appropriate economic analysis"; and (4) AEPCO employs "effective management practices and mechanisms for managing gas supply."

- Gas Hedging (pages 7-8) – (1) AEPCO has established an appropriate objective for its gas hedging program; (2) "in pursuing its hedging objective, AEPCO applies effective strategies, and uses appropriate instruments"; and (3) "AEPCO applies appropriate risk-management policies and procedures."

- Power Transactions (pages 8-9) – (1) "AEPCO effectively manages the scheduling, real-time dispatch, and trading functions associated with making power purchases and sales"; (2) "AEPCO's power trading operations have established effective processes and methods for arranging economic term purchases of power"; and (3) "AEPCO's processes for soliciting long-term power resources have been thorough and effective."

- Engineering Analysis/Plant Operations (pages 10-11) – (1) "Technical performance, personnel and facilities are generally sound, and AEPCO's management team is capable, knowledgeable, and supported with appropriate tools"; (2) "AEPCO's power plant operations are generally appropriate and typical of the industry"; (3) "AEPCO's investment in new and upgraded facilities has been appropriate for the demands placed on the Cooperative, and maintenance practices and spending appear to be consistent with the station's needs and good utility practice"; and (4) "AEPCO employs good practices in preparing for and managing outages."
- PPFAC (pages 13-14) – (1) Liberty does not recommend the use of forecasted costs for setting a power cost adjustor rate and costs and revenues from transactions involving SO2 allowances should not be included in the clause and (2) AEPCO's proposed modifications to the clause are appropriate "to align amounts recovered from individual members more closely with the hourly costs they impose on AEPCO."

Q. Mr. Pierson, as you mentioned, in addition to those conclusions, Liberty's Prudence Review also stated certain concerns and offered related recommendations. Did you discuss these with the appropriate AEPCO managers and personnel?

A. Yes, I did. Those individuals analyzed each recommendation and discussed with me the following comments and responses.

1 **Fuel Contracting**

2 **Q. Please comment on Liberty's recommendation regarding fuel contracting at page 5**
3 **of Mr. Antonuk's testimony.**

4 A. Liberty recommends that AEPCO solicit interest from additional suppliers beyond its
5 traditional sources for our forward gas purchases. While it doesn't believe the effort will
6 cut costs, Liberty does think the additional solicitation will verify that best costs are being
7 obtained. In that regard, AEPCO is working with ACES Power Marketing ("ACES") to
8 develop International Swaps & Derivatives Association agreements with additional
9 suppliers subject to suitable credit requirements, terms and conditions. In addition,
10 ACES, as a result of its extensive trading operations, is able to provide timely
11 information to AEPCO on forward gas prices and market movement so that we can
12 compare the terms of our gas purchases against that market data. We believe that
13 comparison is a similar kind of check on "best costs" as Liberty suggests.

14 **Fuel Supply Management**

15 **Q. What were Liberty's recommendations regarding fuel supply management?**

16 A. At page 7 of his testimony, Mr. Antonuk stated three recommendations: (1) "AEPCO
17 should undertake a formal process for examining the causes of differences between
18 physical and book inventory, and take corrective action, as appropriate"; (2) "AEPCO
19 should develop a plan for reducing the coal inventory level at Apache Station"; and
20 (3) "AEPCO should explore the creation of a set of specific performance measures for its
21 traders."

1 **Q. Please provide AEPCO's response to Liberty's recommendation on the differences**
2 **between physical and book inventory.**
3 A. AEPCO's current reconciliation process involves semi-annual surveys of the coal
4 stockpile in December and June. An outside consultant conducts a volume density
5 survey and adjustments are made to our book inventory according to those survey results
6 after review by AEPCO management with Board of Directors' approval. AEPCO will
7 review this process to determine the cause of 2009 differences using a team consisting of
8 the Plant Manager, the Coal Yard and Limestone Quality Manager, the Plant
9 Performance Engineer, the Fuels Resource Administrator and representatives from
10 Finance and/or Accounting and Internal Auditing. This team will review all aspects of
11 the current process and will recommend all appropriate modifications to the current
12 practices.

13 **Q. What is AEPCO's response to Liberty's recommendation as to a plan for reducing**
14 **the coal inventory level at Apache Station?**
15 A. AEPCO is pursuing various stockpile reduction strategies and we've already had some
16 success. Due to production problems at the coal supplier's mine, 108,000 tons were not
17 delivered in June. The parties have agreed that these tons will be deferred to a future
18 year. An additional 54,000 tons will not be delivered during the month of August and
19 AEPCO is discussing deferring these tons to a future year as well. We expect the
20 stockpile will be reduced to a 95-105 days level[3] by the end of this year—a significant,

[3] Estimated stockpile level is based upon an average burn of 3,300 tons per day.

1 roughly 40 days improvement from 2009 year end levels. We are hopeful that ongoing
2 renegotiation, deferral and other reduction efforts will produce the 75-day target stockpile
3 level which Liberty recommends sometime next year.

4 **Q. Finally, as to this subject area, please provide AEPCO's response to exploring**
5 **creation of specific performance measurements for gas traders.**
6 A. AEPCO agrees. We have already had discussions with ACES to identify appropriate
7 measurements and how these performance measurements should be implemented.

8 **Gas Hedging**
9 **Q. Please provide AEPCO's response to Mr. Antonuk's recommendation, at page 8 of**
10 **his testimony, that AEPCO adopt a program to measure hedging program results.**
11 A. AEPCO understands the recommendation. We are also consulting with ACES to identify
12 the appropriate ways to measure hedging results and the process to implement them.

13 **Q. What is AEPCO's response to Liberty's recommendation that its Internal Auditing**
14 **Group should periodically review the processes and systems for the tracking of gas**
15 **hedging transactions?**
16 A. As an initial matter, I would note that AEPCO's future hedging activity is going to be
17 sharply reduced once Trico completes its conversion from an all- to a partial-
18 requirements member ("PRM") and the amendments to the existing PRM Agreements are
19 approved. In short, Trico's conversion and the amendments mean that AEPCO's gas
20 hedging activities will be reduced to cover only the requirements of operating the Steam

Turbine Unit 1 at a 20 MW minimum for only a four-month summer period and flame stabilization gas for the coal units. That much reduced hedging scope obviously will sharply reduce the program's current size and the potential risk and financial exposure associated with it. However, in response to Liberty's concerns, AEPCO's Internal Audit Department will address the recommendation regarding periodic reviews of gas hedging processes and transaction tracking in the 2011 internal audit plan. AEPCO's Internal Audit Department allocates resources to audit projects like this by using a risk analysis methodology. By including Liberty's recommendation in the next risk analysis, AEPCO will evaluate how to incorporate the gas hedging program into its audit plans.

<u>Power Transactions</u>

Q. What recommendations did Liberty offer on power transactions?

A. On page 10 of his testimony, Mr. Antonuk recommended that (1) "AEPCO should require its partial requirements members and Salt River Project ("SRP") to make timely submissions of pre-scheduling power requirements" and (2) "AEPCO should undertake a series of steps to assure the Commission that it has effectively completed, can demonstrate, and will periodically audit the effectiveness of the new adjustor clause processes."

Q. Please provide AEPCO's response to the recommendation that AEPCO require timely submissions of pre-scheduling power requirements.

A. We have recently firmed up that pre-scheduling requirement and filed it with the Commission for approval. Exhibit B-1 to Schedule B of the PRM Agreements submitted

1 to the Commission on June 2, 2010 in AEPCO's Joint Request for PRM
2 Contract/Amendments Approvals establishes procedures that require the PRMs to make
3 timely submissions of pre-scheduling power requirements. Preliminary estimated pre-
4 schedules must be submitted by 1600 hours of the day prior to the trading day. Final pre-
5 schedules must be submitted by 0630 of the trading day. AEPCO believes that these
6 procedures adequately address Liberty's recommendation in connection with the PRMs.
7 Because AEPCO's contract with SRP terminates in four months, AEPCO does not
8 believe that further action is needed regarding SRP's pre-schedules.

9 **Q. Please provide AEPCO's response to Liberty's recommendation that AEPCO**
10 **should undertake a series of steps to assure the Commission that it has effectively**
11 **completed, can demonstrate and will periodically audit the effectiveness of the new**
12 **adjustor clause processes.**
13 A. We are in the process of undertaking such steps. As Liberty notes, we have already
14 instituted "significant" changes which should minimize or eliminate future errors. In
15 addition, AEPCO has drafted a PPFAC Plan for Administration that it has provided to Staff.
16 Also, AEPCO is developing written PPFAC processes and procedures which we will
17 accelerate, as Liberty suggests, to the first quarter of 2011. Finally, as to more frequent
18 audits, we have already scheduled an audit of the clause for next year and will conduct more
19 frequent reviews.

1 **Engineering Analysis/Plant Operations**

2 **Q. What recommendations were made regarding engineering and plant operations?**

3 A. On page 13 of his testimony, Mr. Antonuk stated three recommendations: (1) "AEPCO
4 should conduct a study of the future role of Apache and how that role relates to member
5 needs for future power supply"; (2) "AEPCO should examine methods to create more
6 structured and formal outage planning and maintenance"; and (3) "AEPCO should
7 examine the root causes of trips resulting from personnel errors."

8 **Q. Please provide AEPCO's response to Liberty's first recommendation.**

9 A. We agree with Mr. Antonuk's statement that the key question about Apache cycling and
10 availability is whether the 2009 experience was anomalous or a warning of continued
11 deterioration. AEPCO believes 2009 was an anomaly for the following reasons:
12 (1) 2009 was the coal-fired units' first year of operation under a new low Btu, high
13 sulphur coal supply; (2) the higher prices caused by AEPCO's new coal contract led to
14 SRP's much lower scheduling of its 100 MW contract with AEPCO; (3) maintenance
15 problems associated with changes in the coal-fired units' scrubber and stack operations
16 led to an unusual spike in downtime; and (4) the continuing economic downturn has
17 simply lessened demand for the units' output. We have already seen improved
18 performance results in 2010. The units' availability factor has returned to the mid-90s
19 range—where it was consistently before 2008-2009. But, the question of whether the
20 units will cycle more frequently in the future very much depends upon the scheduling of
21 these units by the PRMs under the amended and new PRM Agreements and we have no
22 experience with that new condition. AEPCO believes that its base resource rates will be

1 competitive with the alternatives available to the PRMs and, therefore, they will schedule
2 these resources to meet their loads. However, whether they will be able to market their
3 available off-peak and shoulder excess base resources to fully load these units depends
4 upon, among other things, economic conditions, market conditions and prices in 2011.
5 AEPCO cannot adequately address the concerns of Liberty without at least a full year's
6 operation under the new power requirements contracts. Once the 2011 data is available,
7 AEPCO can then address whether a study of the future role of Apache, in light of
8 member needs and actual usage, is appropriate.

9 **Q. Does AEPCO agree that it should create more structured and formal plans for**
10 **outage and maintenance?**
11 A. Yes. We are planning to prepare Summary Outage Plans, as recommended by Liberty,
12 approximately five to six months prior to each outage. The Summary will then be
13 periodically updated prior to the outage as plans evolve.

14 **Q. Please provide AEPCO's response to Liberty's recommendation that AEPCO**
15 **should examine the root causes of trips resulting from personnel errors.**
16 A. In response to the recommendation, the following action plan has been developed:
17 i. Two individuals (instead of one) will be permanently assigned to review and
18 report, including a root cause analysis, on all large equipment failures and forced
19 unit outages on the Apache coal- and gas-fired boiler configured units.
20 ii. This report will consist of a statement from the originator of the trip, the control
21 room operator assigned to the affected unit, the operations manager and a final

summary with specific recommendations on how to avoid the problem in the future from the individual(s) assigned to this task.

iii. The information will then be reviewed to see if there are specific trends that may identify a particular problem area that needs to be addressed.

iv. An additional training program through GPiLEARN, which is specifically directed to power plant operations, is being initiated to better train and prepare employees to anticipate and avoid potential problems.

PPFAC

Q. Finally, did Liberty's Prudence Review contain any recommendations regarding AEPCO's PPFAC?

A. On page 14 of his testimony, Mr. Antonuk stated two recommendations: (1) "AEPCO should address through focused discussions with the Class A members the means of introducing in an orderly fashion a change that will produce more current [PPFAC] recovery"; and (2) AEPCO "needs to establish a temporary surcharge mechanism, and clarify the proposed plan for administering it."

Q. Please provide AEPCO's response to Liberty's first recommendation.

A. We are not certain that we need to further shorten the bank recovery period. Primarily as a result of the Commission authorization in Decision No. 70354 to change the amortization of the bank balance two years ago to a six- rather than 12-month period and moderation of the volatility in gas and purchased power costs, AEPCO's bank balance levels have been dropping. Rather than studying a new option now, AEPCO believes that

1 the "efficacy review" option granted by the Commission in the last rate order should be
2 continued. Thus, if a situation develops requiring a further clause revision, AEPCO
3 could request a modification targeted specifically to known developments.

4 **Q. Please provide AEPCO's response to Liberty's recommendation that the**
5 **Cooperative needs to establish a temporary surcharge mechanism and clarify the**
6 **proposed plan for administering it.**

7 A. We agree with Mr. Antonuk that the most direct means for closing out the old balances is
8 to continue the bank account component of the current clause until whatever balance
9 remaining under it is collected. We are filing on September 1 with Docket Control the
10 calculations for the new October 1 adjustors under the current clause. The three-page
11 schedule showing the calculation of the new adjustors is attached as Exhibit GEP-3.
12 Those calculations show a bank account ("BA") recovery component of 1.12 mills per
13 kWh for all-requirements members ("ARMs") and a BA recovery component of
14 1.68 mills per kWh for PRMs to take effect on October 1. AEPCO proposes to continue
15 those BA components as the temporary surcharges to close out remaining under-collected
16 balances of the current clause. Because Trico has participated in the current clause as an
17 ARM, we will use the ARM BA for Trico as its surcharge. We will account for the
18 collections on a member-by-member basis, so that no member under- or overpays its
19 contribution to the under-collected total bank. In the unlikely event that any member has
20 contributed too much to the under-collected bank, the same BA component will be used
21 to refund that overpayment. At the end of the month following collection (or return) of

1 all under-collections (or over-collections), we will file a report in this docket
2 summarizing surcharge close-out results on a monthly and a total basis.

3 **Q. Mr. Pierson, when does AEPCO recommend that the first semi-annual adjustor**
4 **occur under the new PPFAC and how will it be calculated?**
5 A. We recommend that the first semi-annual fuel adjustor be filed on September 1, 2011 to
6 become effective on October 1, 2011. It would be based upon data covering the 12
7 months ended June 30, 2011. Thereafter, AEPCO would make fuel adjustor filings to
8 become effective on April 1 or October 1 based upon historical periods of the prior 12
9 months ended December 31 or June 30, respectively.

10 **Q. Does this conclude your Rebuttal Testimony?**
11 A. Yes, it does.

Arizona Electric Power Cooperative, Inc.

Comparison of Increase in Gross Revenue Requirement

Test Year Ended March 31, 2009

Line No.	Description	Col. 1 Company As Amended Position	Col. 2 Staff Direct Position	Col. 3 Company Rebuttal Position
1	Summary of Revenue Increase Proposed:			
2	Proposed Revenue Increase	$ (96,754)	$ 231,014	$ (1,172,317)
3	Revenues in Test Year - Present Rates	$ 166,618,639	$ 166,618,639	$ 166,618,639
3	Revenue Increase Percentage	-0.06%	0.14% (1)	-0.70%
4				
5	Pro Forma Statement of Operations			
6	with Proposed Rates:			
7	Operating Revenues	$ 178,665,925	$ 178,993,693	$ 177,590,362
8	Operating Expense	164,623,661	162,820,299	162,820,299
9	Electric Operating Margins	14,042,264	16,173,394	14,770,063
10	Interest & Other Deductions	11,917,826	11,822,642	11,822,642
11	Operating Margins	2,124,438	4,350,752	2,947,421
12	Non-Operating Margins	1,112,155	1,112,155	1,112,155
13	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576
14				
15	Times Interest Earned Ratio:			
16	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576
17	Interest on Long Term Debt	10,812,194	10,812,194	10,812,194
18	Total	$ 14,048,787	$ 16,275,101	$ 14,871,770
19	Times Interest Earned Ratio	1.299	1.505	1.375
20				
21	Debt Service Coverage Ratio:			
22	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576
23	Depreciation & Amortization	8,348,168	8,317,632	8,317,632
24	Interest on Long Term Debt	10,812,194	10,812,194	10,812,194
25	Total	$ 22,396,955	$ 24,592,733	$ 23,189,402
26				
27	Interest on Long Term Debt	$ 10,812,194	$ 10,812,194	$ 10,812,194
28	Principal Payments	6,754,044	6,754,044	6,754,044
29	Debt Service	$ 17,566,238	$ 17,566,238	$ 17,566,238
30	Debt Service Coverage Ratio	1.275	1.400	1.320
31				
32	Return on Fair Value Rate Base:			
33	Electric Operating Margins	$ 14,042,264	$ 16,173,394 (1)	$ 14,770,063
34	Rate Base	$ 231,844,975	$ 211,802,594	$ 211,802,594
35	Return on Fair Value Rate Base	6.06%	7.64% (1)	6.97%

(1) Per Direct Testimony of Dennis M. Kalbarczyk.

Arizona Electric Power Cooperative
Computation of All Requirements Power Cost Adjustor Rate
Twelve Months Ended June 30, 2010

All Requirements Tariff Formula - Power Cost Adjustor Rate:

F = (PC + BA) - $0.01687

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

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

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

Computation of PC:

Pro Forma Fuel, Purchased Power and Wheeling Costs	$ 36,984,650.11
All Requirements kWh sales	894,813,845
All Requirements PC - $/kWh	$0.04133

Computation of BA:

All Requirements Under Collected Balance - as of June 30, 2010	$ 65,182,702.08
All Requirements Amount Recovered Through FPPCA	$ 64,735,340.05
All Requirements Total Under Collected Balance - as of June 30, 2010	$ 447,362.04
All Requirements kWh sales	400,431,689
All Requirements BA - $/kWh	$0.00112

Computation of All Requirements
Power Cost Adjustor Rate - $/kWh

F = ($ 0.04133 + $ 0.00112) - $ 0.01687
F = $ 0.04245 - $ 0.01687
F = $ 0.02558

Adjustor Rate for October 1, 2010	$0.02558
Current Adjustor Rate Effective April 1, 2010	$0.03117
Increase to Adjustor Rate	($0.00559)

Arizona Electric Power Cooperative
Computation of Partial Requirements Power Cost Adjustor Rate
Twelve Months Ended June 30, 2010

Partial Requirements Tariff Formula - Power Cost Adjustor Rate:

F = (PC + BA) - $0.01603

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

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

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

Computation of PC:

Pro Forma Fuel, Purchased Power and Wheeling costs	$ 46,475,762.22
Partial Requirements kWh sales	1,348,538,000
Partial Requirements PC - $/kWh	$0.03446

Computation of BA:

Partial Requirements Under Collected Balance - as of June 30, 2010	$89,269,046.21
Partial Requirements Amount Recovered Through FPPCA	$ 88,163,504.01
Partial Requirements Total Under Collected Balance - as of June 30, 2010	$ 1,105,542.20
Partial Requirements kWh sales	659,018,000
Partial Requirements BA - $/kWh	$0.00168

Computation of Partial Requirements Power Cost Adjustor Rate - $/kWh

F = ($0.03446 + $ 0.00168) - $0.01603
F = $0.03614 - $ 0.01603
F = $0.02011

Adjustor Rate for October 1, 2010	$0.02011
Current Adjustor Rate Effective April 1, 2010	$0.02006
Increase to Adjustor Rate	$0.00005

Arizona Electric Power Cooperative, Inc.
Computation of All Requirement and Partial Requirement Members
Twelve Months Ended June 30, 2010

Description		State 1 Member Fuel Cost	State 2 & 3 Member Fuel Cost	Total Member Fuel Cost	ARM kWh Sales	PRM kWh Sales	Total kWh Sales	Allocated ARM State 1 Member Fuel Costs	Allocated ARM State 2 Member Fuel Costs	Total ARM Member Fuel Costs	Total PRM Member Fuel Costs	Total Member Fuel Costs
July-09		$ 8,372,153.83	$ 1,416,760.60	$ 9,788,914.43	109,942,442	126,508,000	236,450,442	$ 3,892,803.20	$ 1,416,760.60	$ 5,309,563.80	$ 4,479,350.63	$ 9,788,914.43
August-09		8,989,271.10	$ 1,487,249.71	10,476,520.81	106,406,543	126,109,000	232,515,543	4,113,777.73	1,487,249.71	5,601,027.44	4,875,493.37	10,476,52[illegible]
September-09		6,812,442.97	$ 549,055.04	7,361,498.01	85,388,578	111,606,000	196,994,578	2,952,897.61	549,055.04	3,501,952.65	3,859,545.36	7,361,49[illegible]
October-09		5,857,485.63	$ 627,417.00	6,484,902.63	65,043,951	108,945,000	173,988,951	2,189,759.79	627,417.00	2,817,176.79	3,667,725.84	6,484,902.63
November-09		4,759,633.63	$ -	4,759,633.63	59,129,016	95,041,000	154,170,016	1,825,468.14	-	1,825,468.14	2,934,165.49	4,759,633.63
December-09	(1)	8,987,983.37	$ -	8,987,983.37	68,471,626	121,311,000	189,782,626	3,242,772.26	-	3,242,772.26	5,745,211.11	8,987,983.37
January-10	(2)	6,615,640.29	$ -	6,615,640.29	64,608,244	122,122,000	186,730,244	2,288,996.65	-	2,288,996.65	4,326,643.64	6,615,640.29
February-10		5,251,671.66	$ -	5,251,671.66	57,225,157	108,598,000	165,823,157	1,812,338.76	-	1,812,338.76	3,439,332.90	5,251,671.66
March-10		6,516,344.68	$ -	6,516,344.68	60,918,556	109,595,000	170,513,556	2,328,063.04	-	2,328,063.04	4,188,281.64	6,516,344.68
April-10		4,356,190.07	$ -	4,356,190.07	57,998,109	96,032,000	154,030,109	1,640,268.83	-	1,640,268.83	2,715,921.24	4,356,190.07
May-10		5,161,945.71	$ 637,050.51	5,798,996.22	67,593,053	103,477,000	171,070,053	2,039,583.57	637,050.51	2,676,634.08	3,122,362.14	5,798,996.22
June-10		5,533,557.86	$ 1,528,558.67	7,062,116.53	92,088,570	119,194,000	211,282,570	2,411,829.00	1,528,558.67	3,940,387.67	3,121,728.86	7,062,116.53
Total		$77,214,320.80	$ 6,246,091.53	$83,460,412.33	894,813,845	1,348,538,000	2,243,351,845	$ 30,738,558.58	$ 6,246,091.53	$ 36,984,650.11	$ 46,475,762.22	$83,460,412.33

(1) December '09 reflects an adjustment to Allocated Member Fuel and Purchased Power Costs for various corrections for the period July 1, 2009 thru December 31, 2009.
This adjustment amounted to an upward adjustment of $3,816.

(2) January '10 reflects an adjustment to Allocated Member Fuel and Purchased Power Costs for the re-pricing of interchange.
This adjustment amounted to an upward adjustment of $333,233.99 as a result of the Company's year-end closing process.

EXHIBIT
A-5
ADMITTED

REJOINDER TESTIMONY OF

GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

October 6, 2010

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1 **REJOINDER TESTIMONY OF GARY E. PIERSON**

2 **ON BEHALF OF**

3 **ARIZONA ELECTRIC POWER COOPERATIVE, INC.**

4 **Q. Mr. Pierson, are you the same Gary E. Pierson who sponsored Direct, Supplemental**
5 **Direct and Rebuttal Testimonies for AEPCO in this matter?**
6 A. Yes, I am.

7 **Q. Have you reviewed the Surrebuttal Testimonies of Staff witnesses Messrs. Smith,**
8 **Antonuk and Kalbarczyk?**
9 A. Yes, I have. My Rejoinder Testimony will respond to various issues raised in their
10 testimonies. I will also discuss the status of the Rural Utilities Service ("RUS") review of
11 the contracts and contract amendments we filed for Commission approval in the Request
12 for Contract Amendment Approvals and Joint Request for Contract/Amendments
13 Approvals on June 2, 2010. Finally, I will present exhibits that summarize AEPCO's
14 final recommendations regarding revenue requirements, proposed forms of a tariff and
15 schedule, Purchased Power and Fuel Adjustment Clause ("PPFAC") bases and
16 recommended rates.

17 **RESPONSE TO MR. SMITH'S SURREBUTTAL TESTIMONY**

18 **Q. On surrebuttal, Mr. Smith notes the agreement between Staff and AEPCO on**
19 **almost all issues and indicates that Staff agrees with AEPCO's normalized annual**

rate case expense allowance amount of $160,000. He states at page 3 of his Surrebuttal Testimony that the sole remaining disagreement between Staff and AEPCO is Staff's recommendation of a Debt Service Coverage ("DSC") ratio of 1.40 and AEPCO's recommendation of a 1.32 DSC. Do you agree with Mr. Smith's assessment of this case's status?

A. Yes, I do. AEPCO is requesting a revenue decrease of about $1.172 million, while Staff recommends a revenue increase of slightly more than $230,000. Mr. Smith is correct that the approximately $1.4 million difference is entirely attributable to the DSC recommendations. For reasons I'll discuss shortly—including a quite favorable development which occurred just last month in relation to AEPCO's coal purchases—AEPCO continues to support the DSC recommendation of 1.32.

RESPONSE TO MR. ANTONUK'S SURREBUTTAL TESTIMONY

Q. At page 3 of his Surrebuttal Testimony, Mr. Antonuk recommends the preparation of an action plan by AEPCO in relation to Liberty's recommendations regarding fuel contracting, fuel supply management, gas hedging, power transactions, engineering analysis/plant operations and the PPFAC. Following preparation of that plan, he recommends quarterly reporting concerning implementation to AEPCO's Board and that copies of those reports be filed with the Commission. Please provide AEPCO's response.

A. We agree with Mr. Antonuk's suggestion. AEPCO should be able to file the completed plan by February 1, 2011. In addition, AEPCO proposes to file with the Director of the Utilities Division quarterly reports concerning the action plan until all items are

1 accomplished. In that regard, certain aspects of the plan or the reports concerning it may
2 contain confidential and/or commercially sensitive information. Therefore, we would ask
3 that the Commission authorize in this Order the filing of any such information on a
4 confidential basis. We will also communicate periodically with Staff if action plan
5 implementation difficulties are encountered or changes to it are necessary.

6 **Q. Do you have any other points to make concerning the recommendations?**

7 A. Yes. I want to clarify, as my Rebuttal Testimony indicates, that actions have already
8 been taken or are scheduled to be taken on several of Liberty's recommendations.
9 Briefly, to summarize:

10 • Concerning the reconciliation of physical/book inventory differences, a
11 team consisting of the individuals identified at page 10 of my Rebuttal
12 Testimony has been formed. It will soon commence the review to
13 determine the cause of the differences, as well as any process
14 improvements which should be made.

15 • As to the auditing recommendation concerning gas hedging transactions,
16 the Internal Audit Department has placed that recommendation in the 2011
17 internal audit plan risk analysis.

18 • The PRM pre-scheduling power requirements issue has been addressed in
19 Exhibit B-1 to Schedule B of the PRM agreements which we submitted for
20 Commission approval on June 2, 2010.

21 • We also are in the process of undertaking a series of steps to assure the
22 Commission as to the effectiveness of the new PPFAC, including, but not

limited to, scheduling an audit of the clause for next year and conducting more frequent reviews.

- Concerning Liberty's recommendation for more structured plans for outage and maintenance, as well as examination of the root causes of trips, Summary Outage Plans will be prepared five to six months prior to each outage and an action plan has been developed to address the issue of trip causation.
- Finally, my Rebuttal Testimony at pages 16-18 responded to Liberty's PPFAC recommendations, including our recommendations that this Order authorize AEPCO to establish a temporary surcharge mechanism to close out the current clause balances.

These items will be included in the complete action plan which is under development.

RESPONSE TO STAFF'S REVENUE REQUIREMENTS POSITION

Q. At pages 3-4 of his Surrebuttal Testimony, Mr. Antonuk states Staff's surrebuttal position concerning a 1.40 DSC. Please provide AEPCO's rejoinder position on revenue requirements.

A. Mr. Antonuk refers to several issues which were raised by Mr. Vickroy on direct in support of his 1.40 DSC recommendation. As background, before we prepared our rebuttal position, AEPCO carefully reviewed Mr. Vickroy's testimony and his concerns about fuel volatility, the financing costs associated with capital expenditures and increases in post-test year expenses, including expected mercury control costs. AEPCO then met several times with the Member Rates Committee to discuss the adequacy of

1 AEPCO's position of a 1.275 DSC in light of those concerns. After consideration of
2 Mr. Vickroy's points, AEPCO's management recommended, and AEPCO's Board
3 authorized, increasing our request for margin requirements to a 1.32 DSC level instead of
4 the earlier amended position of 1.275. We continue to believe that a 1.32 DSC—which
5 falls well within Mr. Vickroy's target range of 1.25 to 1.45—will provide adequate
6 revenues and margins. Further, a quite favorable development which occurred about ten
7 days after I filed my Rebuttal Testimony concerning our coal purchases has reinforced
8 that position.

9 **Q. Please discuss this recent development.**

10 A. At page 10 of my August 30 Rebuttal Testimony, I discussed AEPCO's efforts to reduce
11 the coal inventory levels at Apache Station. They included a tentative agreement
12 between CoalSales and AEPCO to defer the delivery of and payment for 162,000 tons to
13 a future year. Those possible deferrals were in response to a *force majeure* situation
14 earlier this summer at the CoalSales mine. About ten days after my testimony was filed,
15 AEPCO and CoalSales representatives met to discuss this *force majeure* situation. But,
16 they were not able to reach a final agreement on either party's deferral proposal. Under
17 the contract, absent a good faith agreement on alternate delivery (which we were not able
18 to reach), CoalSales does not have an obligation to deliver, and AEPCO does not have an
19 obligation to pay for, the coal tonnage impacted by the *force majeure*. CoalSales has
20 calculated AEPCO's share of this impacted tonnage to be 141,100 tons.

1 **Q. Please explain how this positively impacts AEPCO.**

2 A. As a result of not having to take delivery of the 141,100 tons, AEPCO's working capital
3 has been increased by their cost, which is approximately $7.7 million. When I filed my
4 Rebuttal Testimony, we believed this $7.7 million expense would only be deferred until
5 2011 or 2012. That certainly would have assisted cash flow on a short-term basis, but
6 would not have permanently improved our cash and financial position. Now, because of
7 this *force majeure* development, the $7.7 million expense has instead been permanently
8 avoided. To place that amount in context—as Mr. Minson testified in his Direct
9 Testimony—AEPCO's objective is to build toward $20 million in working capital over
10 the next several years. This $7.7 million avoided cash outlay obviously is a significant
11 step toward that goal and allowed us to pay off the outstanding balance on our line of
12 credit. It also reinforces the sufficiency of our request for a 1.32 DSC and the
13 approximately $2.95 million in annual operating margins it is expected to produce.

14 **Q. Mr. Antonuk also cites Mr. Vickroy's concern about an increase in operating**
15 **expense resulting from new mercury control expenses as support for the 1.40 DSC**
16 **recommendation. Will AEPCO be able to recover those new expenses through the**
17 **PPFAC?**

18 A. Yes. As a result of initial testing, it has been determined that the new mercury control
19 chemical treatment will be applied to the coal at the point at which the coal is conveyed
20 from the stockpile to the coal bunkers. Therefore, the treatment costs are recoverable
21 through AEPCO's PPFAC, which allows for recovery of all costs recorded in RUS
22 Account 501. RUS Account 501-Fuel states in part that, "This account shall include the

1 cost of fuel used in the production of steam for the generation of electricity, including
2 expenses in unloading fuel from the shipping media and handling thereof up to the point
3 where the fuel enters the first boiler plant bunker, hopper, bucket, tank, or holder of the
4 boiler-house structure."[1] Because the mercury control chemicals will be applied in the
5 handling process before the coal (fuel) enters the bunker, the mercury costs will be
6 recoverable through the PPFAC. Therefore, there is no need to increase the DSC request
7 in anticipation of this expense.

8 **Q. Messrs. Antonuk and Vickroy also note fuel price volatility as a risk to AEPCO's**
9 **financial status. Please respond.**

10 A. Having coped with the extreme volatility of fuel prices a few years ago, we certainly do
11 not dismiss those concerns. However, the markets have calmed considerably in the wake
12 of the economic turndown and current forward indicators are for continuing, relative
13 price stability. AEPCO has also instituted fuel supply management and gas hedging
14 strategies to help us ameliorate the effects of any price fluctuations. As well, we have
15 two "fixed" price years remaining on our coal contract, which also is a positive,
16 stabilizing factor. Additionally, with Trico's conversion to PRM status, approximately
17 90% of our Class A member load requirements are now fixed. While that does not
18 remove the volatility risk associated with meeting that load, it has shifted from AEPCO
19 to the PRMs that risk as to any future load growth. Finally, Mr. Antonuk indicates that
20 Staff does support our request to continue the "efficacy option" of the last rate order.

[1] 7 CFR 1767-Accounting Requirements for RUS Electric Borrowers, Subpart B-Uniform System of Accounts, § 1767.27. (Emphasis supplied.)

1 That will continue to allow us promptly to bring to the Commission requests for reviews
2 and modifications of cost recovery under the PPFAC should circumstances require such
3 action. Given all of these factors, we believe we do have sufficient protections in place to
4 manage fuel price volatility without the necessity of increasing rates now to
5 accommodate a 1.40 DSC.

6 **Q. Finally, Messrs. Antonuk and Vickroy cite post-test year capital expenditures in**
7 **their testimonies as a justification for a higher DSC.**
8 A. AEPCO agrees that the financing costs associated with capital expenditures will result in
9 increased revenue requirements pressure. That factor, however, is a primary reason why
10 we increased our DSC request from 1.275 to 1.32 on rebuttal. Given all of these
11 considerations, we continue to urge that the Commission approve the 1.32 DSC.

12 **CONTRACTS AND CONTRACT AMENDMENTS STATUS**

13 **Q. Please discuss the status of the RUS review of the contracts and contract**
14 **amendments which AEPCO filed for Commission approval in this rate case docket**
15 **on June 2, 2010 (the "Contracts").**
16 A. Briefly, to summarize, the Contracts we filed in June primarily provide for three things:
17 (1) Trico's conversion to PRM status, which we are reflecting in our proposed rates;[2]
18 (2) certain changes to cost allocation and rate design methods, which are included in the
19 rates we have proposed and which have been reviewed by Staff;[3] and (3) the changes to

[2] *See* GEP-5; Company Rejoinder Column.
[3] Kalbarczyk Surrebuttal Testimony; pp. 2-5 and Table II.

1 the PPFAC, "whose purpose is to align amounts recovered from individual members
2 more closely with the hourly costs they impose on AEPCO."[4] AEPCO has also filed
3 those Contracts with RUS. We are scheduled to meet with RUS on October 20, 2010 to
4 discuss them. AEPCO has requested that RUS complete its review promptly and approve
5 the Contracts. AEPCO also requests that the Commission approve the Contracts in this
6 Order.

7 **SUMMARY OF REQUESTS**

8 **Q. Have you prepared exhibits which summarize AEPCO's rejoinder position?**

9 A. Yes, I have. Exhibit GEP-4 sets forth AEPCO's and Staff's positions as the case has
10 moved from direct to rejoinder. As shown on Exhibit GEP-4, Column 5, AEPCO's
11 rejoinder position remains the same as our rebuttal position. We request a 0.70%
12 decrease over test year present rates based upon a DSC of 1.32. This would produce
13 operating revenues of approximately $177.6 million; net margins of about $4.1 million;
14 TIER and DSC ratios of 1.375 and 1.32, respectively; and a return of 6.97% on the fair
15 value rate base of just over $211.8 million.

16 **Q. Have you also prepared an exhibit which shows AEPCO's requested rates?**

17 A. Yes, I have. As noted in Mr. Kalbarczyk's Surrebuttal Testimony,[5] Staff and AEPCO
18 agree on cost of service and rate design issues. Therefore, the only difference between
19 AEPCO's rejoinder rates and Staff's surrebuttal rates is the $1.4 million difference in our

[4] Antonuk Direct Testimony, p. 14, ll. 1-3.
[5] Kalbarczyk Surrebuttal Testimony, p. 5.

1 revenue requirements positions. Exhibit GEP-5 summarizes the proposed rates
2 associated with the various positions set forth on Exhibit GEP-4. Column 6 shows the
3 rates that AEPCO requests the Commission approve. In addition, the exhibit sets forth
4 the recommended PPFAC bases based upon AEPCO's rejoinder position.

5 **Q. Have you also prepared a form of all-requirements tariff and a partial-requirements**
6 **schedule?**
7 A. Yes. We have previously provided these forms to Staff. They are attached with minor
8 modifications and also include AEPCO's recommended rates. Exhibit GEP-6 is
9 AEPCO's proposed rate tariff and PPFAC language for the collective ARMs and
10 Exhibit GEP-7 provides the schedule and PPFAC language for AEPCO's PRMs.

11 **Q. Can you estimate the impact that AEPCO's proposed rates would have on the retail**
12 **member/owner's bill?**
13 A. As mentioned in Mr. Minson's Direct Testimony, it is difficult to provide precise
14 estimates, because the distribution cooperatives have different retail rates for different
15 classes, as well as varying rate structures and purchased power adjustment mechanisms.
16 However, generation service accounts for about 55% of the costs of the total delivered
17 rate at retail. Assuming a residential rate of 14 cents per kWh, an average eight cents of
18 that rate would be attributable to AEPCO's generation service. Therefore, we estimate
19 that an ARM residential consumer using 1,000 kWh per month would see about a $1.80
20 <u>decrease</u> in the monthly bill; a Mohave Electric Cooperative residential consumer using
21 the same amount would see about a $1.80 <u>increase</u>; a Sulphur Springs Valley Electric

Cooperative residential consumer using the same amount would see about a $0.50 increase; and a Trico Electric Cooperative residential consumer using that same 1,000 kWh would see about a $4.20 decrease in the monthly bill as a result of this rate request. When these approximate increases or decreases would be flowed through to the retail level would also be dependent on the terms and status of each distribution cooperative's adjustment clause.

Q. Please provide AEPCO's recommendation to establish a temporary surcharge mechanism for closing out the existing fuel bank balances as of the effective date of the recommended rates.

A. As mentioned in my Rebuttal Testimony on pages 17-18, AEPCO proposes a temporary surcharge of 1.12 mills per kWh for ARMs and 1.68 mills per kWh for PRMs, effective at the same date as the new rates authorized in the Order. These temporary surcharges will remain in effect until AEPCO collects each member's remaining under-collected balances under the current clause. Because Trico has participated in the current clause as an ARM, AEPCO recommends using the ARM temporary surcharge for Trico as well. AEPCO will account for the collections on a member-by-member basis, so that no member under- or overpays its contribution to the under-collected total bank. In the event that any member has contributed too much to the under-collected bank, the same temporary surcharge rate will be used to refund that overpayment. At the end of the month following collection (or return) of all under-collections (or over-collections), we will file a report in this docket summarizing surcharge close-out results on a member-by-member and total basis.

1 **Q. Does AEPCO also request that the Order authorize continuation of the so-called**
2 **"efficacy" provision in relation to the PPFAC?**
3 A. Yes. We recommend the language used at page 16 of Decision No. 68071: "IT IS
4 FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. may file a request
5 that the Commission review the efficacy of the [PPFAC] with Arizona Electric Power
6 Cooperative, Inc.'s submission of any semi-annual… report required by this Decision."
7 As discussed at page 18 of my Rebuttal Testimony, we recommend that the first semi-
8 annual fuel adjustor be filed on September 1, 2011, to become effective on October 1,
9 2011.

10 **Q. Finally, Mr. Pierson when does AEPCO request that the new rates become**
11 **effective?**
12 A. We ask that the Contracts be approved and the new rates take effect with usage from and
13 after January 1, 2011. However, as I mentioned previously, we must have RUS approval
14 for the Contracts, as well as for Trico's conversion to PRM status, prior to the new rates
15 taking effect. If we do not receive RUS approval by December as we expect, we will
16 promptly notify the Commission and request that the rates' effective date be postponed
17 accordingly.

18 **Q. Does this conclude your testimony?**
19 A. Yes it does.

EXHIBIT GEP-4

Arizona Electric Power Cooperative, Inc.

Comparison of Increase in Gross Revenue Requirement

Test Year Ended March 31, 2009

Line No.	Description	Col. 1 Company As Amended Position	Col. 2 Staff Direct Position	Col. 3 Company Rebuttal Position	Col. 4 Staff Surrebuttal Position	Col. 5 Company Rejoinder Position
1	Summary of Revenue Increase Proposed:					
2	Proposed Revenue Increase	$ (96,754)	$ 231,014	$ (1,172,317)	$ 231,014	$ (1,172,317)
3	Revenues in Test Year - Present Rates	$ 166,618,639	$ 166,618,639	$ 166,618,639	$ 166,618,639	$ 166,618,639
3	Revenue Increase Percentage	-0.06%	0.14% (1)	-0.70%	0.14%	-0.70%
4						
5	Pro Forma Statement of Operations					
6	with Proposed Rates:					
7	Operating Revenues	$ 178,665,925	$ 178,993,693	$ 177,590,362	$ 178,993,693	$ 177,590,362
8	Operating Expense	164,623,661	162,820,299	162,820,299	162,820,299	162,820,299
9	Electric Operating Margins	14,042,264	16,173,394	14,770,063	16,173,394	14,770,063
10	Interest & Other Deductions	11,917,826	11,822,642	11,822,642	11,822,642	11,822,642
11	Operating Margins	2,124,438	4,350,752	2,947,421	4,350,752	2,947,421
12	Non-Operating Margins	1,112,155	1,112,155	1,112,155	1,112,155	1,112,155
13	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576	$ 5,462,907	$ 4,059,576
14						
15	Times Interest Earned Ratio:					
16	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576	$ 5,462,907	$ 4,059,576
17	Interest on Long Term Debt	10,812,194	10,812,194	10,812,194	10,812,194	10,812,194
18	Total	$ 14,048,787	$ 16,275,101	$ 14,871,770	$ 16,275,101	$ 14,871,770
19	Times Interest Earned Ratio	1.299	1.505	1.375	1.505	1.375
20						
21	Debt Service Coverage Ratio:					
22	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576	$ 5,462,907	$ 4,059,576
23	Depreciation & Amortization	8,348,168	8,317,632	8,317,632	8,317,632	8,317,632
24	Interest on Long Term Debt	10,812,194	10,812,194	10,812,194	10,812,194	10,812,194
25	Total	$ 22,396,955	$ 24,592,733	$ 23,189,402	$ 24,592,733	$ 23,189,402
26						
27	Interest on Long Term Debt	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194
28	Principal Payments	6,754,044	6,754,044	6,754,044	6,754,044	6,754,044
29	Debt Service	$ 17,566,238	$ 17,566,238	$ 17,566,238	$ 17,566,238	$ 17,566,238
30	Debt Service Coverage Ratio	1.275	1.400	1.320	1.400	1.320
31						
32	Return on Fair Value Rate Base:					
33	Electric Operating Margins	$ 14,042,264	$ 16,173,394 (1)	$ 14,770,063	$ 16,173,394	$ 14,770,063
34	Rate Base	$ 231,844,975	$ 211,802,594	$ 211,802,594	$ 211,802,594	$ 211,802,594
35	Return on Fair Value Rate Base	6.06%	7.64% (1)	6.97%	7.64%	6.97%

(1) Per Direct Testimony of Dennis M. Kalbarczyk.

EXHIBIT GEP-5

Exhibit GEP-5

Arizona Electric Power Cooperative, Inc.

Comparison of Proposed Rates & PPFAC Bases

Test Year Ended March 31, 2009

Description	Col. 1 Company Current Rates	Col. 2 Company As Amended Position Supplemental (2)	Col. 3 Staff Direct Position (3)	Col. 4 Company Rebuttal Position	Col. 5 Staff Surrebuttal Position	Col. 6 Company Rejoinder Position
Collective All-Requirements Members: (1)						
Demand Rate $/kW	$ 14.98	N/A	N/A	N/A	N/A	N/A
Fixed Charge - $/mo.		$ 232,978	$ 931,105	$ 238,793	$ 251,168	$ 238,793
O&M Charge - $/mo.		$ 436,144	$ 1,178,484	$ 414,019	$ 414,019	$ 414,019
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03157	$ 0.03234	$ 0.03156	$ 0.03156	$ 0.03156
Other Resources $/kWh		$ 0.06069	$ 0.06746	$ 0.06170	$ 0.06170	$ 0.06170
PPFAC Bases: (4)						
Current $/kWh	$ 0.01687					
Base Resources $/kWh		$ 0.03377		$ 0.03361		$ 0.03361
Other Resources $/kWh		$ 0.07634		$ 0.07941		$ 0.07941
Partial-Requirements Members:						
Mohave Electric Cooperative						
Fixed Charge - $/mo.	$ 855,113	$ 709,721	$ 764,975	$ 727,283	$ 764,976	$ 727,283
O&M Charge - $/mo. (Present $/kW)	$ 7.26	$ 1,323,724	$ 1,274,882	$ 1,274,882	$ 1,274,882	$ 1,274,882
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03216	$ 0.03215	$ 0.03215	$ 0.03215	$ 0.03215
Other Resources $/kWh		$ 0.06879	$ 0.06879	$ 0.06879	$ 0.06879	$ 0.06879
PPFAC Bases: (4)						
Current $/kWh	$ 0.01603					
Base Resources $/kWh		$ 0.03331		$ 0.03330		$ 0.03330
Other Resources $/kWh		$ 0.07504		$ 0.06971		$ 0.06971
Sulphur Springs Valley						
Fixed Charge - $/mo.	$ 757,429	$ 628,440	$ 677,366	$ 643,991	$ 677,366	$ 643,991
O&M Charge - $/mo. (Present $/kW)	$ 7.26	$ 1,172,125	$ 1,128,876	$ 1,128,876	$ 1,128,876	$ 1,128,876
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03230	$ 0.03229	$ 0.03229	$ 0.03229	$ 0.03229
Other Resources $/kWh		$ 0.06676	$ 0.06676	$ 0.06676	$ 0.06676	$ 0.06676
PPFAC Bases: (4)						
Current $/kWh	$ 0.01603					
Base Resources $/kWh		$ 0.03338		$ 0.03337		$ 0.03337
Other Resources $/kWh		$ 0.07775		$ 0.07241		$ 0.07241
Trico Electric Cooperative						
Demand Rate per kW	$ 14.98	N/A	N/A	N/A	N/A	N/A
Fixed Charge - $/mo.		$ 629,365	N/A	$ 646,435	$ 679,937	$ 646,435
O&M Charge - $/mo. (Present $/kW)		$ 793,509	N/A	$ 764,465	$ 764,465	$ 764,465
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03234	N/A	$ 0.03238	$ 0.03238	$ 0.03238
Other Resources $/kWh		$ 0.06612	N/A	$ 0.06604	$ 0.06604	$ 0.06604
PPFAC Bases: (4)						
Current $/kWh	$ 0.01687					
Base Resources $/kWh		$ 0.03331		$ 0.03336		$ 0.03336
Other Resources $/kWh		$ 0.07634		$ 0.09084		$ 0.09084

1) The Fixed Charge and the O&M Charge will be apportioned among the CARMs and allocated to each CARM based upon each CARM's monthly Demand Ratio Share. The Demand Ratio Share will be calculated each month as the percentage of each CARM's 12-month rolling average demand to the total of the CARMs' 12-month rolling average demand.

2) Amended Filing initially included Trico as part of the CARMs. The Company subsequently filed rates that treated Trico as a PRM pursuant to a contract submitted for ACC approval.

3) Staff witness Kalbarczyk did not develop rates for Trico as a PRM in his direct testimony.

4) Staff witness Kalbarczyk did not take issue with the Company's derivation of the PPFAC bases.

EXHIBIT GEP-6

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

TARIFF

PERMANENT

Effective Date: January 1, 2011

AVAILABILITY

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

MONTHLY RATE (BILLING PERIOD)

Electric power and energy furnished under this Tariff will be subject to the rates set forth in the attached Exhibit A and the terms set forth herein in addition to any applicable terms set forth in the Member's Wholesale Power Contract.

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

Demand Overrun Adjustment – If, in any hour, the CARM's metered load exceeds its Allocated Capacity, then AEPCO shall compute a Demand Overrun Adjustment for the CARM and each Member shall be charged a portion of such Demand Overrun Adjustment in proportion to that Member's demand ratio share. Such Demand Overrun Adjustment shall equal the product of the CARM's Fixed Charge multiplied by the demand overrun adjustment factor. The demand overrun adjustment factor shall be any non-negative number determined from the following formula:

$$doaf = ((mbdkW) / AC) - 1$$

Where:

doaf	=	Demand Overrun Adjustment Factor,
mbdkW	=	Metered kW of CARM, and
AC	=	Allocated Capacity of CARM, in kW.

In addition, Member shall pay for the energy associated with the Demand Overrun Adjustment at the then-applicable Other Resources Energy Rate.

Power Factor – Each Member shall maintain Power Factor at the time of maximum demand as close to unity as possible. If the Power Factor of Member measured at the aggregated Member's Delivery Point(s) at the time of Member peak demand is outside a bandwidth of 95% leading to 95% lagging, a Power Factor Adjustment shall be separately charged to the Member. The Power Factor Adjustment shall be the product of the Member's power factor adjustment (as set forth

below) multiplied by the quotient of the Member's demand ratio share of the CARM O&M Charge divided by the sum of the CARM's 12-month rolling average demand. The power factor adjustment shall be any non-negative number determined from the following formula:

$$pfakW = ((mkW / mpf)(bpf)) - mkW$$

Where:

pfakW	=	power factor adjustment in kW,
mkW	=	Member Metered kW,
mpf	=	measured power factor at the time of Member peak demand, and
bpf	=	0.95.

The provisions of the power factor adjustment may be waived if power factor is detrimentally impacted as a direct result of system improvements or a change in operational procedure by AEPCO to reduce transmission losses and/or improve system reliability.

Capacity and Energy Below Allocated Capacity – If CARM is utilizing a Future Resource, Supplemental Purchase or S&G PPA in any hour to serve Native Load and CARM fails to take its required share of Minimum Base Capacity or Minimum Other Capacity, CARM shall pay a charge as set forth in Section 2.4 of Rate Schedule A to the Member's Wholesale Power Contract.

Taxes – Bills rendered are subject to adjustment for all federal, state and local government taxes or levies, including any taxes or levies imposed as a carbon tax or "cap and trade" or other carbon assessments system imposed on electricity sales or electricity production and any assessments that are or may be imposed by federal or state regulatory agencies on electric utility gross revenues.

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

Power Cost Adjustor Rates

"Base Resources" are defined as (1) AEPCO's Steam Turbine Units 2 and 3, (2) power purchased under contract from the Western Area Power Administration and (3) economy purchases displacing base resources generation.

"Other Resources" are defined as (1) AEPCO's generation units other than Steam Turbine Units 2 and 3, (2) power purchased under contracts which serve the combined scheduled loads of AEPCO's Class A members plus power purchased under contract and economy energy purchases (other than economy purchases displacing base resources generation) made for the purpose of meeting the scheduled load requirements of all Class A members and (3) power purchased under contracts or resources which have been acquired to serve Class A Member load and which the Member has expressly agreed to in a participation agreement.

The monthly bill computed under this Tariff shall, using the procedures stated herein, be increased or decreased by an amount equal to the result of multiplying the kWh derived from each resource type by the applicable Power Cost Adjustor Rate for Base Resources and Other Resources where:

Base Resources Adjustor Rate

BF = (BPC + BBA) - $.003361

BF = Base Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

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

BBA = The "Base Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over- or under-collected in the past from Base Resources. The BBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Base Resources kWh energy sales.

Allowable Base Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 2 and 3 as recorded in RUS Account 501, plus

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

C. The cost of energy purchased when such energy is purchased on an economic dispatch basis to substitute for higher cost Base Resources energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of Base Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the collective all-requirements Class A members, less

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

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Base Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

Other Resources Adjustor Rate

OF = (OPC + OBA) - $0.07941

OF = Other Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

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

OBA = The "Other Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over- or under-collected in the past from Other Resources. The OBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Other Resources kWh energy sales.

Allowable Other Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 1, 4, 5 and 6 as recorded in RUS Accounts 501 and 547, plus

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

C. The cost of Other Resources energy purchased when such energy is purchased on an economic dispatch basis. Included therein are such costs as those charged for economy energy purchases and the charges resulting from a scheduled outage of Other Resources generation units. All such kinds of Other Resources energy being purchased by AEPCO to substitute for its own higher cost Other Resources energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of Other Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the collective all-requirements Class A members, less

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

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Other Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

On a calendar semi-annual basis, AEPCO shall compute the Power Cost Adjustor Rates as specified herein based upon a rolling 12-month average of allowable fuel, purchased power and wheeling costs for the BPC and the OPC plus the bank balance amortization component for the BBA and OBA. AEPCO shall initially file by September 1, 2011 and thereafter on March 1 or September 1 of the month preceding the effective date of the revised Power Cost Adjustor Rates (i.e., April 1 or October 1): (1) calculations supporting the revised Adjustor Rates with the Director, Utilities Division, and (2) a Tariff reflecting the revised Adjustor Rates with the Commission which shall be effective for billings after the first day of the following month and which shall continue in effect until revised pursuant to the procedures specified herein.

EXHIBIT A

Effective Date	January 1, 2011*
Collective All-Requirements Members:	
Total Fixed Charge/Month	$238,793**
Total O&M Charge/Month	$414,019**
Base Resources Energy Rate – $/kWh	$0.03156
Other Resources Energy Rate – $/kWh	$0.06170

Base Resources Power Cost Adjustor Rate – $/kWh $0.00000***
Other Resources Power Cost Adjustor Rate – $/kWh $0.00000***

* Rates are effective for service provided on and after this date.

** The Total Fixed Charge and the Total O&M Charge will be apportioned among the CARMs and allocated to each CARM based upon each CARM's monthly Demand Ratio Share. The Demand Ratio Share will be calculated each month as the percentage of each CARM's 12-month rolling average demand to the total of the CARMs' 12-month rolling average demand.

*** Effective January 1, 2011 and determined and revised as set forth in the Tariff.

EXHIBIT GEP-7

Arizona Electric Power Cooperative, Inc.

Partial-Requirements Schedule
Rates and Fixed Charge
(Effective January 1, 2011)

Service provided to Mohave Electric Cooperative, Inc. ("MEC"), Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") and Trico Electric Cooperative, Inc. ("Trico") by the Arizona Electric Power Cooperative, Inc. ("AEPCO") under the Partial Requirements Capacity and Energy Agreements shall be at the rates set forth in the attached Exhibit A and subject to the terms set forth herein in addition to any applicable terms set forth in the Members' Partial Requirements Capacity and Energy Agreement.

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

Demand Overrun Adjustment – If, in any hour, (i) Member's scheduled load (if Member is not in AEPCO's Control Area) or (ii) Member's metered load less capacity obtained from sources outside the Dispatch Pool (if Member is in AEPCO's Control Area) exceeds its Allocated Capacity, then Member shall be charged a Demand Overrun Adjustment. Such Demand Overrun Adjustment shall equal the product of Member's Fixed Charge multiplied by the demand overrun adjustment factor. The demand overrun adjustment factor shall be any non-negative number determined from the following formula:

$$doaf = ((mbdkW) / AC) - 1$$

Where:

doaf	=	Demand Overrun Adjustment Factor,
mbdkW	=	Member Schedule in kW or Metered kW less capacity from sources outside the Dispatch Pool, as applicable, and
AC	=	Allocated Capacity of Member, in kW.

In addition, Member shall pay for the energy associated with the Demand Overrun Adjustment at the then-applicable Other Resources Energy Rate.

Power Factor – Each Member shall maintain Power Factor at the time of maximum demand as close to unity as possible. If the Power Factor of Member measured at the aggregated Member's Delivery Point(s) at the time of Member's peak demand is outside a bandwidth of 95% leading to 95% lagging, a Power Factor Adjustment shall be separately charged to the Member. The Power Factor Adjustment shall be the product of the Member's power factor adjustment (as set forth below) multiplied by the quotient of the Member's O&M Charge divided by the sum of the Member's 12-month rolling average demand. The power factor adjustment kW shall be any non-negative number determined from the following formula:

$$pfakW = ((mkW / mpf)(bpf)) - mkW$$

Where:

pfakW	=	power factor adjustment in kW,
mkW	=	Member Metered kW,
mpf	=	measured power factor at the time of Member peak demand, and
bpf	=	0.95.

The provisions of the power factor adjustment may be waived if power factor is detrimentally impacted as a direct result of system improvements or a change in operational procedure by AEPCO to reduce transmission losses and/or improve system reliability.

Taxes – Bills rendered are subject to adjustment for all federal, state and local government taxes or levies, including any taxes or levies imposed as a carbon tax or "cap and trade" or other carbon assessments system imposed on electricity sales or electricity production and any assessments that are or may be imposed by federal or state regulatory agencies on electric utility gross revenues.

Power Cost Adjustor Rates

"Base Resources" are defined as (1) AEPCO's Steam Turbine Units 2 and 3, (2) power purchased under contract from the Western Area Power Administration and (3) economy purchases displacing base resources generation.

"Other Resources" are defined as (1) AEPCO's generation units other than Steam Turbine Units 2 and 3, (2) power purchased under contracts which serve the combined scheduled loads of AEPCO's Class A members plus power purchased under contract and economy energy purchases (other than economy purchases displacing base resources generation) made for the purpose of meeting the scheduled load requirements of all Class A members and (3) power purchased under contracts or resources which have been acquired to serve Class A Member load and which the Member has expressly agreed to in a participation agreement.

The monthly bill computed under this Tariff shall, using the procedures stated herein, be increased or decreased by an amount equal to the result of multiplying the kWh derived from each resource type by the applicable Power Cost Adjustor Rate for Base Resources and Other Resources where:

Base Resources Adjustor Rate

BF = (BPC + BBA) - BFB

BF = Base Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

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

BBA = The "Base Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over- or under-collected in the past from Base Resources. The BBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Base Resources kWh energy sales.

BFB = The Base Resources Fuel Base or BFB is $0.03330 for MEC, $0.03337 for SSVEC and $0.03336 for Trico.

Allowable Base Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 2 and 3 as recorded in RUS Account 501, plus

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

C. The cost of energy purchased when such energy is purchased on an economic dispatch basis to substitute for higher cost Base Resources energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of Base Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the all-requirements Class A members, less

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

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Base Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

<u>Other Resources Adjustor Rate</u>

OF = (OPC + OBA) - OFB

OF = Other Resources Power Cost Adjustor Rate in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

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

OBA = The "Other Resources Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over- or under-collected in the past from Other Resources. The OBA component is determined by dividing the over-collected or under-collected bank balance dollars by six months of Other Resources energy sales.

OFB = The Other Resources Fuel Base or OFB is equal to $0.06971 for MEC, $0.07241 for SSVEC and $0.09084 for Trico.

Allowable Other Resources fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's Steam Generating Units 1, 4, 5 and 6 as recorded in RUS Accounts 501 and 547, plus

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

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

D. The firm and non-firm wheeling expenses associated with the delivery of Other Resources energy as recorded in RUS Account 565, excepting network service transmission payments made by AEPCO to Southwest Transmission Cooperative, Inc. for electric power and energy furnished to the all-requirements Class A members, less

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

F. The demand and energy costs recovered through inter-system economy energy and/or intra-system resource transfer sales of Other Resources power and energy sold on an economic dispatch basis as recorded in RUS Account 447.

On a calendar semi-annual basis, AEPCO shall compute the Power Cost Adjustor Rates as specified herein based upon a rolling 12-month average of allowable fuel, purchased power and wheeling costs (BPC and OPC) plus a bank balance amortization component (BBA and OBA). AEPCO shall initially file by September 1, 2011 and thereafter on March 1 or September 1 of the month preceding the effective date of the revised Power Cost Adjustor Rates (i.e., April 1 or October 1): (1) calculations supporting the revised Adjustor Rates with the Director, Utilities Division, and (2) a Tariff reflecting the revised Adjustor Rates with the Commission which shall be effective for billings after the first day of the following month and which shall continue in effect until revised pursuant to the procedures specified herein.

EXHIBIT A

Effective Date	January 1, 2011*		
Partial Requirements Members:	MEC	SSVEC	Trico
Fixed Charge – $/month	$727,283	$643,991	$646,435
O&M Charge – $/month	$1,274,882	$1,128,876	$764,465
Base Resources Energy Rate – $/kWh	$0.03215	$0.03229	$0.03238
Other Resources Energy Rate – $/kWh	$0.06879	$0.06676	$0.06604

MEC

Base Resources Power Cost Adjustor Rate – $/kWh 0.00000**
Other Resources Power Cost Adjustor Rate – $/kWh 0.00000**

SSVEC

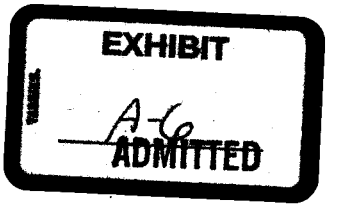
Base Resources Power Cost Adjustor Rate – $/kWh 0.00000**
Other Resources Power Cost Adjustor Rate – $/kWh 0.00000**

Trico

Base Resources Power Cost Adjustor Rate – $/kWh 0.00000**
Other Resources Power Cost Adjustor Rate – $/kWh 0.00000**

* Rates are effective for service provided on and after this date.
** Effective January 1, 2011 and determined as set forth in the Tariff.

EXHIBIT
A-6
ADMITTED



DIRECT TESTIMONY OF
GARY L. GOBLE
ON BEHALF OF
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
GENERAL RATES APPLICATION

I. POSITION AND QUALIFICATIONS

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

A. My name is Gary L. Goble. I am a consultant with the firm of Management Applications Consulting, Inc. ("MAC"). MAC's primary office is 1103 Rocky Drive, Suite 201, Reading, Pennsylvania 19609. My office is located at 11405 Cezanne Court, Austin, Texas 78726.

Q. In what capacity and on whose behalf are you employed in this proceeding?

A. I have been retained to provide consulting services and testimony relating to the costs of providing service and the rates charged to the Class A Members of Arizona Electric Power Cooperative, Inc. ("AEPCO"). In this proceeding, I am testifying on behalf of AEPCO and, in particular, in support of Schedules G and H of the rate filing package. This testimony addresses the allocation of costs to AEPCO's two partial-requirements and four all-requirements Class A Members. Furthermore, relying upon the results of my cost allocation, I have prepared and testify in support of proposed rates that are designed to recover these allocated costs.

Q. Please outline your education, experience and professional qualifications.

A. I am a consultant with more than 35 years of experience in regulatory matters. I have undergraduate and graduate degrees in business and have worked as a staff analyst for two regulatory commissions and as a consultant to the utility industry. I have testified before state and local regulatory agencies and boards on numerous occasions. The primary focus of my work experience has been in the areas of cost analysis, pricing and economic analysis. Please refer to Exhibit GLG-1 for more detailed information concerning my education, experience and professional qualifications.

II. ALLOCATED COST OF SERVICE

Q. Please describe what is meant by the phrase "allocated cost of service".

A. "Allocated cost of service" refers to the process by which all of a utility's revenue requirements are assigned, or allocated, among customers or customer classes on some rational basis. An allocated cost of service study identifies the detailed cost components that comprise a utility's revenue requirement, as well as the cost drivers that influence or cause these costs to be incurred. Once the cost drivers associated with costs are identified, the costs are allocated based upon the notion of cost causation. In this manner, customers who cause the costs to be incurred bear the responsibility of paying for those costs. Because all components that make up the utility's revenue requirement are allocated to customers or classes, these studies are often referred to as "fully distributed" cost of service studies.

Q. Generally, what are the steps involved in conducting an allocated cost of service study?

A. The steps employed to conduct an allocated cost of service study are functionalization, classification and allocation. Functionalization is the arrangement of costs according to major service functions, such as production, transmission or distribution. Functionalization is generally accomplished by the process of recording investment and expenses in accordance with a prescribed uniform accounting system, such as the Rural Utilities Service Uniform System of Accounts which is used by AEPCO. For example, production plant is booked in accounts 301 through 346, and production expenses are booked in accounts 500 through 557. Other costs relating to general plant, customer-related expenses and administrative and general expense are similarly booked in specific accounts that recognize the underlying purpose of the expenditure.

Classification further refines functionalized costs into categories to which general cost drivers can be ascribed. These categories are generally demand, energy, customer and revenue classifications. For example, fuel costs arise as a result of energy consumption and are, therefore, classified as energy-related costs. Grouping functionalized costs into cost classifications allows analysts to develop factors for apportioning (*i.e.,* allocating) costs to customers or customer classes.

The final allocation step employs utility metrics that reflect customer or class contributions to the cost drivers as the basis for allocating costs. Class contribution to system peak demands may be used to allocate production plant. Energy sales adjusted for losses may be used to allocate fuel costs.

Q. Was the allocated cost of service process described above used in connection with AEPCO's rate application?

A. Yes, it was. However, as I discuss later, AEPCO's cost of service methodology is also the product of significant input from its members and also reflects the specific service generation resource obligations to its partial-requirements and all-requirements members.

Q. Is this allocated cost of service process consistent with the Arizona Corporation Commission's rate application filing requirements?

A. Yes. These steps are recognized in Schedule G of the Commission's rate filing requirements. For example, Schedules G-5 and G-6 provide for the functionalization of rate base and expenses and Schedules G-3 and G-4 provide for the allocation of rate base and expenses to customer classes. However, as discussed later, not all of the Schedule G filing requirements are applicable to AEPCO in light of its organizational structure and customer makeup. Additionally, AEPCO's generation cost functionalization analysis is specially tailored to account for the differing cost responsibilities between the two partial-requirements Class A Members—Mohave Electric Cooperative, Inc. ("MEC") and Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC")—and four all-requirements Class A Members.

Q. Please describe the generation cost functionalization utilized in allocating AEPCO's cost of service.

A. AEPCO's generation cost functionalization analysis employs three functional categories: Base Resources, Other Existing Resources and Additional ARM Resources.

The first category, Base Resources, is comprised of AEPCO's coal-fired Apache Steam Units 2 and 3 and certain base load purchased power contracts (such as the Colorado River Storage Project ("CRSP") and the Parker Davis Project, which are part of the Western Area Power Administration ("WAPA") power). MEC and SSVEC participate in and receive output from these base load resources in fixed proportions according to their allocated capacity percentages as set forth in their respective partial-requirements agreements. Specifically, MEC is entitled to 35.8% of the base load supply, SSVEC is entitled to 31.7% and the four all-requirements members (which are treated as a single entity for cost allocation and rate design purposes) are entitled to the remaining 32.5%. Consequently, each partial-requirements member and the collective all-requirements members bear their percentage share of the costs of these base load resources.

The second category—Other Existing Resources—primarily consists of AEPCO's gas-fired units at Apache and other operational purchases. Similar to the assignment of Base Resources, the capital and non-energy-related operating costs of Other Existing Resources are assigned to members in accordance with their allocated capacity percentages. Because these resources are utilized by the partial-requirements and all-requirements members as needed, the energy-related costs of these resources are assigned to members on an "as used" basis as determined by the hourly dispatch model discussed below. The final category—Additional ARM Resources—is utilized

exclusively by the all-requirements members. An example of this type of resource would be a seasonal peaking purchased power contract secured specifically to meet ARM loads.

Q. How are these categories used to allocate costs?

A. In order to allocate the Other Existing Resources and Additional ARM Resources costs consistent with cost causation principles, AEPCO has used an hourly matching of load requirements against available supply resources to match the partial-requirements members' hourly load schedules to the available hourly power supplies. When the partial-requirements members' scheduled load exceeds their allocated share of capacity available from Base Resources, the remaining load requirements are then matched to their share of AEPCO's Other Existing Resources. Similarly, the all-requirements members' hourly loads are initially matched to their allocated hourly Base Resources. Any unmet demand is matched first to their share of Other Existing Resources and then to other Additional ARM Resources. If scheduled loads are less than Base Resources, the available unused Base Resource capacity is available to other members at market prices. By assigning the costs of the three supply functions (Base Resources, Other Existing Resources and Additional ARM Resources) on an hour-by-hour basis, AEPCO simultaneously functionalizes the expenses of these resources and allocates the associated costs to MEC, SSVEC and the all-requirements members.

Q. Please describe Schedules G-1 and G-2 of AEPCO's rate filing.

A. Schedule G-1 summarizes AEPCO's margins and rate of return for the adjusted test year at present rate levels. Although AEPCO's revenue requirements do not employ a rate base to develop returns, this schedule shows the effective level of return to comport with the filing requirements of the Commission. Schedule G-2, page 1 provides similar information at the proposed rate level. Schedule G-2, page 2 refers to the derivation of proposed rates on Schedule G-4, page 1.

Q. Please describe Schedule G-3.

A. Schedule G-3 concerns the allocation of rate base to classes of service. Because AEPCO's revenue requirement is not driven by a rate of return on rate base (*i.e.,* AEPCO is a non-profit, member-owned cooperative), this schedule is not applicable.

Q. Please describe Schedule G-4.

A. Schedule G-4, page 1 provides the derivation of revenue requirements and rates for MEC, SSVEC and the all-requirements members. Costs which have been functionalized as Base Resources, Other Existing Resources and Additional ARM Resources on Schedule G-6 have also been further categorized as fixed costs, capacity-related operation and maintenance expenses or energy-related expenses on Schedule G-6, page 5. After netting certain adjustments, including other revenues and the revenues received from the transfer and use of resources by other members, against the energy-related costs on Schedule G-4, page 2 revenue requirements by customer by function are aggregated on Schedule G-4, page 1. These cost groupings are then employed on lines 35 through 41 of Schedule G-4, page 1 to develop the Fixed Charge and O&M

Charge dollar amounts for MEC and SSVEC, as well as the Fixed Charge Rate and the O&M Charge Rate for the all-requirements members (lines 36-38). In addition, by identifying and grouping energy costs by resource function, separate energy charges for MEC, SSVEC and the all-requirements members were developed which reflect the specific supply resource costs attributable to each of these Class A Members (lines 39-41).

Q. Please describe Schedule G-5.

A. Schedule G-5 concerns the development and presentation of rate base by function. As previously explained, AEPCO does not employ a rate base to develop its revenue requirement. Therefore, this schedule is not applicable.

Q. Please describe Schedule G-6.

A. Schedule G-6 provides the detailed functionalization of expenses to Base Resources, Other Existing Resources and Additional ARM Resources. Schedule G-6, page 1 summarizes the account-by-account assignment of expenses after reclassifications have been made to the three resource functions. Schedule G-6, page 2 provides the account-by-account assignment of booked expenses to the three resource functions. Production fuel expense, account 501, is by far the single largest component of costs. This account reflects the coal costs associated with Apache Steam Units 2 and 3 and is functionalized to Base Resources. Similarly, operations and maintenance expenses associated with the Base Resources units (accounts 502, 505, 506, 509, 511, 512, 513 and 514) are functionalized to the Base Resources function. Production fuel expense (account 547)

is the fuel costs of the Other Existing Resources and is functionalized accordingly. The operations and maintenance expenses associated with Other Existing Resources (accounts 546, 548, 549, 552, 553 and 554) are also assigned to Other Existing Resources in a consistent manner.

Purchased Power expense (account 555) was assigned to functions based upon contractual obligations. That is, the energy and demand costs of the WAPA contracts were assigned to Base Resources since these agreements are firm base load supply contracts. However, the members have agreed that the costs associated with the South Point Energy Center ("Calpine"), PPL Energy Plus ("Griffith") and Powerex contracts are all-requirements member resources and, thus, on a going forward basis, the costs of these PPAs should be assigned to Additional ARM Resources. The remaining purchased power costs reflect purchases made to serve the entire AEPCO load and are, therefore, functionalized as Other Existing Resources.

System Control and Load Dispatching (account 556), Other Expenses (account 557) and Transmission of Electricity by Others (account 565, excluding a directly assigned amount associated with the Liberty to Marana transmission transaction) were functionalized on the basis of the proportions of energy from each of the three resource types insofar as the scheduling and transmission of this energy is the cost driver for these costs. Station Expense (account 562), Underground Line Expense (account 564) and Maintenance of Station Equipment (account 570) were functionalized on the basis of the related functionalization of fuel expense accounts 501 and 547. Administrative

and General Expense and General Plant Expense were functionalized on the basis of the functionalized labor component of the other operation and maintenance expense accounts.

The remaining cost components of AEPCO's revenue requirements were similarly assigned to functions based upon the appropriate cost drivers. Depreciation expense was assigned based upon the amount of depreciation associated with each generation unit. The depreciation associated other non-generating equipment was pro-rated on the basis of directly determined depreciation expense by function. Similarly, Interest on Long-Term Debt was directly calculated by function and assigned accordingly with the small amount of indirect interest functionalized on a pro-rata basis. The remaining other interest and deductions were addressed in the same manner. Total booked expenses by function were then totaled and are set forth on line 59 of Schedule G-6, page 2.

Q. Please describe how the pro forma adjustments made by AEPCO were functionalized.

A. Schedule G-6, page 3 provides the distribution of AEPCO's pro-forma adjustments to test year expenses to the functions of Base Resources, Other Existing Resources and Additional ARM Resources. On this page, each of the pro forma adjustments described by Mr. Pierson has been assigned to the specific account and resource function affected by the adjustment.

The labor expense adjustment has been distributed to the various operation and maintenance accounts and resource functions on the basis of the booked labor by account which was, in turn, functionalized on the same basis as the adjusted expenses set forth on Schedule G-6, page 1. The labor adjustment affects numerous accounts and resource functions to which labor costs are booked. The Base Resources function of fuel expense (account 501) was adjusted to reflect the various pro-forma adjustments described in Mr. Pierson's testimony. The Base Resources function of steam expense (account 502) was adjusted for the mercury control pro forma adjustment. The Other Existing Resources and Additional ARM Resources functions of purchased power expense (account 555) were decreased to reflect (1) the pro forma adjustment for the expiration of the PNM PPA, (2) decreases in purchased power costs associated with increased use of Other Existing Resources resulting from the expiration of the City of Mesa ("Mesa") contract and (3) the removal and/or modification of the purchased power agreements as discussed by Mr. Pierson. The Base Resources function of transmission of Electricity by Others (account 565) reflects the reduction in point-to-point costs associated with the Salt River Project adjustment, to reflect a reduction in system control and load dispatching costs and to reflect the decrease in Mesa transmission expenses. The Other Existing Resources function of maintenance of electric plant (account 513), maintenance of structures (account 552) and maintenance of generating and electric equipment (account 553) was reduced to reflect each account's pro rata portion of the maintenance outage adjustment. The Depreciation expense adjustment and adjustment for Interest on Long-Term Debt were assigned to functions based upon the associated costs from Schedule G-6, page 1. Finally, the

adjustment for interest associated with the SAP software was assigned to functions based upon the functionalization of depreciation expense.

Total pro forma adjustments by function were totaled and are set forth on line 59 of Schedule G-6, page 3.

Q. Please describe how the reclassification of expenses made by AEPCO was functionalized.

A. Schedule G-6, page 4 provides information concerning the distribution of AEPCO's reclassifications of test year expenses to the functions of Base Resources, Other Existing Resources and Additional ARM Resources. The reclassified amounts by account were removed from the functional costs using the same basis as the costs were initially assigned to the respective functions. Coal legal fees included in the Base Resources function of fuel expense (account 501) were removed from this account and reclassified to the Base Resources function of administrative and general expenses. In addition, property taxes were removed (*i.e.,* reclassified) from the various functions of those production operations and maintenance expense accounts in which these costs have been booked. This adjustment affected fuel expense (account 501), steam expenses (account 502), electric operation expenses (account 505), generation operation expenses (account 548) and administrative and general expenses. The reclassifications made to the Base Resources and Other Existing Resources functions of system control and load dispatching (account 556), other power supply expenses (account 557) and transmission of electricity by others (account 565) reflects the removal of Southwest

Transmission Cooperative revenue associated with load control and system dispatch. Finally, the reclassifications made to taxes on line 47 of Schedule G-6, page 4 removed property taxes from the Base Resources and Other Existing Resources functions of various O&M accounts and identified these costs as taxes for ratemaking purposes. Mr. Pierson explains the reclassifications proposed by AEPCO. Total reclassifications by function are totaled and set forth on line 59 of Schedule G-6, page 4.

Q. Please describe how member requirements by function by classification were developed on Schedule G-6, page 5.

A. Schedule G-6, page 5 sets forth the functionalized costs by account provided on Schedule G-6, page 1 with additional breakdowns of adjusted account balances into Fixed, O&M and Energy classifications. This allows the grouping of costs into components useful in the development of rates in Schedule G-4, page 1. As one would expect, the bulk of the operations and maintenance expenses other than fuel and purchased power are classified to O&M. Fixed costs are those costs that do not vary with the level of service. For example, while the vast majority of fuel costs are energy-related, a portion of fuel expense in account 501 is related to natural gas used for flame stabilization in the coal fired generation units and is, thus, fixed in nature rather than energy-related. Similarly, while most of the costs of gas used in the gas-fired Other Existing Resources are energy-related, a portion of those costs is gas reservation charges and is, therefore, fixed, as opposed to energy-related. Property taxes are another component of costs that are considered fixed. The demand component of purchased power costs is also considered to be fixed in nature and is classified as such,

while the variable portion of purchased power is classified as energy-related. Depreciation and interest are fixed costs because they do not change with the level of energy sales.

Q. Schedule G-6, page 5 includes revenue credits that are netted against total expenses. Please describe these revenue credits and explain how they are functionalized and classified.

A. As indicated on Schedule G-2, page 1 (lines 3 and 4) and Schedule G-6, page 5 (line 66) AEPCO receives about $12.1 million of Non-Member and Other Operating Revenues which is used to offset an equal portion of Class A Member revenue requirements. These revenue credits are comprised of Firm Contract Revenues from ED2 firm sales, Economy Energy Sales from AEPCO generation assets, Scheduling Revenues for scheduling services provided to all-requirements members and Other Operating Revenues from miscellaneous sources. The Firm Contract Revenues arise from the sale of capacity and energy from AEPCO's Base Resources and, thus, fixed (*i.e.*, capacity-related) revenue is classified as Fixed and the variable charge revenue is classified as Energy within the Base Resources function. Economy Energy revenue is entirely variable charge revenue and results from both Base Resources sales and from sales from Other Existing Resources. Scheduling Revenues are provided from scheduling services provided exclusively to all-requirements members and are, therefore, functionalized entirely to Additional ARM Resources and classified as O&M related. Other Operating Revenues are provided from sources such as loss charges, banking charges and certain reserve sharing revenues. Because Other Operating

Revenues arise from all AEPCO generation resources, these revenues are functionalized and classified on the basis of Total Expenses prior to Revenue Credits.

Q. How are total Class A Member revenue requirements determined?

A. All classified and functionalized operations and maintenance expenses, depreciation, taxes, interest and other charges are totaled on line 59 of Schedule G-6, page 5. Revenue credits set forth on line 66 are deducted from total expenses and margins are added on line 68. Margins are classified as fixed costs and are assigned to functions on the basis of the total costs of service by function excluding margins. The resulting Class A Member revenue requirements by cost classification and function are provided on line 70 of Schedule G-6, page 5.

Q. Please describe Schedule G-7, page 1.

A. Schedule G-7 summarizes the functionalization factors employed in the assignment of costs in Schedules G-4 and G-6.

III. RATE DESIGN

Q. Mr. Goble, are you also sponsoring Schedules H-1 through H-5?

A. Yes, I am.

Q. Please describe Schedule H-1.

A. Schedule H-1, page 1 summarizes total member and other tariff sales revenues at present and proposed rates, as well as the proposed dollar and percent increases for the test year.

Q. Please describe Schedule H-2.

A. Schedule H-2, page 1 compares present and proposed revenues by member for Class A members and firm contract sales. Schedule H-2, pages 2 through 4 provides billing determinant information used to develop the rates set forth in Schedule G-4, page 1. Schedule H-2, page 2 provides unadjusted MW and MWH sales by Class A Member by month for the test year. Schedule H-2, pages 3 and 4, provides adjusted MW and MWH sales by Class A Member by month for the test year. Schedule H-2, page 4 also provides the adjusted kWh sales by member which are further indentified by resource function (*i.e.,* Base Resources, Other Existing Resources and Additional ARM Resources).

Schedule H-2, pages 5 through 10, provides detailed monthly rate revenue information at actual present and proposed rates for each Class A Member. These pages employ the actual Purchased Power and Fuel Adjustor Clause ("PPFAC") adjustor rate by month for the test year and also provide the dollar and percentage impacts of the proposed revenue changes to base rates and total revenue. Page 11 is a recap schedule that provides a summary of actual present and proposed revenues for all-requirements and partial-requirements members. Page 12 provides the average cost per kWh by Class A Member by month at present and proposed rates.

Schedule H-2, pages 13 through 18, provides the same information as pages 5 through 10, except that the PPFAC factor has been synchronized to allow a consistent comparison of present and proposed rate revenues. A consistent "apples-to-apples" comparison of rate impacts would not be possible when comparing revenues produced by actual test year PPFAC factors derived from actual test year fuel and purchased power costs to revenues produced by rates that employ adjusted test year fuel and purchased power costs. For this reason, present revenues are restated, or synchronized, on Schedule H-2, pages 13 through 18, using a PPFAC that reflects adjusted test year fuel and purchased power costs. Page 19 is a recap schedule summarizing the synchronized present revenues for all-requirements and partial-requirements members. Finally, page 20 provides the average cost per kWh for Class A Members at synchronized present and proposed rates.

Q. Please describe Schedule H-3.

A. Schedule H-3, page 1 identifies the changes in representative rate schedules. Lines 1 through 8 set forth the present monthly charges for MEC, SSVEC and the all-requirements members. Lines 10 through 17 provide the proposed rates for these members. Lines 19 through 26 set forth the changes in the monthly rates from the present rates to the proposed rates. Because AEPCO proposes to apply a fixed monthly O&M charge to the partial-requirements members, the present O&M rate per kilowatt for MEC and SSVEC has been recalculated as total monthly charges for the rate comparison provided on line 21. Similarly, the fixed charge per kilowatt of demand for

the all-requirements members is proposed to be replaced by two demand billing charges, one for recovery of fixed costs and another for recovery of O&M costs. Therefore, line 22 of this page provides a comparison of the total of the two demand charges. Finally, AEPCO proposes to replace the current single base energy charge of each of MEC, SSVEC and the all-requirements members with multiple base energy charges reflecting the three generation resource functions. Therefore, the present base energy charge is compared with the weighted average proposed energy charges for purposes of calculating the base energy charge changes proposed by AEPCO. These base energy charge changes are set forth on line 26 of Schedule H-3, page 1.

Q. Please explain why Schedules H-4 and H-5 are not applicable to AEPCO.

A. Schedule H-4 requires the filing of typical bill analyses to facilitate a comparison of present and proposed rates at varying consumption levels. AEPCO does not have retail customers and has provided actual month-by-month impacts for each Class A Member in Schedule H-2. That provides the "typical" customer information specifically applicable to each customer. Finally, Schedule H-5 requires the filing of billing activity by block for each rate schedule. As stated, AEPCO does not serve any retail customer classes and AEPCO's present and proposed rates do not contain any rate blocks. Therefore, this schedule is not applicable.

Q. Please summarize AEPCO's proposed rates for Class A Members.

A. As explained by Mr. Pierson, AEPCO has worked closely with its Class A members to develop proposed rate forms that take member input into account. Schedule G-4, page

1, lines 27 through 41, shows the development of the proposed rates. Currently, both MEC and SSVEC pay fixed monthly charges, and AEPCO proposes to continue this type of rate. The monthly fixed charges for MEC and SSVEC of $772,376 and $683,919 are stated as fixed dollar amounts to reflect their respective fixed costs. Because they participate in AEPCO resources at fixed allocated capacity percentages, the fixed costs of MEC and SSVEC will neither increase nor decrease (except as a result of inflation or significant changes in AEPCO's overall cost structure[1]). Therefore, it is fair and reasonable to recover fixed costs from these members on a fixed monthly basis rather than through the application of a demand charge. The fixed costs for each of the three proposed Class A member rates are summarized on lines 2 through 6 of Schedule G-4, page 1. For MEC and SSVEC, these fixed costs are simply divided by 12 to derive the monthly fixed charges. For all-requirements members, AEPCO remains obligated to secure sufficient resources to meet load growth. Therefore, it is fair and reasonable to recover all-requirements members' fixed costs by means of a demand charge as is the typical practice in the electric utility industry. Dividing MEC's and SSVEC's Fixed costs by 12 months yields the monthly Fixed Charges for these two members of $772,376 and $683,919, respectively. Dividing the fixed costs of all-requirements members by their billing demands yields a fixed cost rate of $6.036 per kilowatt of billing demand. As indicated on Schedule H-3, lines 11 through 13, and in Mr. Pierson's testimony, the total proposed all-requirements members' demand charge is the sum of the fixed charge and the O&M charge or $14.05 per kilowatt month.

[1] Neither fixed dollar charges nor charges per kilowatt of demand can address changes in inflation or cost structure. Therefore, to the extent that this is a problem with the application of a fixed charge, it is also a problem with the typical demand charge.

Similar reasoning applies to the development of O&M charges for AEPCO'S Class A Members. After extensive discussions with its members, AEPCO proposes to modify its present O&M charges for the PRM from a charge per kilowatt of demand to a fixed monthly charge. As indicated by the cost assignments set forth on Schedule G-6, page 5, most O&M expenses are directly tied to the level of fixed assets operated and maintained by AEPCO. Therefore, for MEC and SSVEC, which have fixed levels of scheduled load and cost responsibility, these costs do not vary as AEPCO's system demand varies. For this reason, it is fair and reasonable to recover these costs on a fixed dollar basis rather than on the basis of a dollar per kilowatt of demand. The monthly O&M charges for MEC and SSVEC are calculated by dividing the allocated O&M costs shown on Schedule G-4, page 1, line 12, by 12. The resulting O&M charges are $1,410,263 and $1,248,752 for MEC and SSVEC, respectively. For all-requirements members, AEPCO remains obligated to secure sufficient resources to meet load growth and to pay for the resulting changes in operation and maintenance expenses. Therefore, it is fair and reasonable to recover all-requirements members' O&M costs by means of a demand charge as is the typical practice in the electric utility industry. The monthly O&M charge for all-requirements members is calculated by dividing the allocated O&M costs shown on Schedule G-4, page 1, line 12, by the members' billing demands. The resulting O&M charge of $8.016 per kilowatt of billing demand is shown on line 37 of this schedule.

AEPCO is proposing to charge separate energy charges for MEC, SSVEC and the all-requirements members and to further separate these energy charges into Base Resources energy charges, Other Existing Resources energy charges and Additional ARM Resources energy charges. Schedule H-3, page 1, sets forth the proposed changes in the Class A members' rate schedules.

Q. Please explain AEPCO's proposal to apply separate energy charges for Base Resources, Other Existing Resources and Additional ARM Resources.

A. The proposal to implement multiple energy charges is the result of a collaborative process between AEPCO and its members. AEPCO and its member cooperatives have discussed this matter extensively and the member cooperatives have participated in a number of meetings to address the issue of separate energy charges to allocate and to recover the costs of separate supply resources. Separate energy charges recognize cost differences among the Class A Members. For example, as shown on Schedule G-4, page 1, line 38, MEC's Base Resources cost is less than the average Base Resources cost, while the Base Resources cost of SSVEC and the all-requirements members is greater than AEPCO's average system Base Resources cost. Conversely, as shown on line 39 of this page, MEC's average cost per kWh of Other Existing Resources is greater than the average cost of the system and greater than either SSVEC's or the all-requirements members' cost. By differentiating the energy charges among the Class A Members, AEPCO is able to more accurately assign and recover energy costs, which has been a subject of considerable and prolonged controversy among the members. Applying separate energy charges for Base Resources, Other Existing Resources and

Additional ARM Resources ensures a more accurate recovery of costs and, thus, provides rates that are fairer than a blended, average cost alternative.

Q. Please describe AEPCO's proposed PPFAC changes.

A. As explained by Mr. Pierson, AEPCO proposes to work with the Staff of the Commission to develop and refine the administrative procedures and calculations necessary to implement refinements to the PPFAC. AEPCO proposes that its PPFAC employ the same procedures to calculate hourly costs by resource as was used to assign fuel and purchased power costs in Schedule G-6. As previously explained, these procedures match hourly load requirements (either scheduled loads for MEC and SSVEC or actual loads for the all-requirements members) with the allocated capacity available to meet the loads in that hour. Under AEPCO's proposal, costs and usage will be accumulated for all hours in the month for each customer (again, the four all-requirements members are treated as a single entity for this calculation) and total costs and usage for the month will be calculated. Unused available capacity from each resource for each member will be available for use by other members, if needed, and will be priced at the then current market price for that period. Load that is unable to be served from Base Resources will be served by Other Existing Resources for all members in accordance with their respective allocated portions of the supply resources and any remaining unserved all-requirements members' load will be served by Additional ARM Resources. The adjustment mechanism will take into account the costs of tariff load, resource transfers, third-party sales, purchased power costs, the

costs of transmission of power by others and will also reduce the recoverable costs by transfer credits and revenues from firm contract and economy energy sales.

Q. Please describe the calculation of the proposed PPFAC bases.

A. The proposed PPFAC bases are calculated in a manner consistent with the manner by which the PPFAC factors will be calculated. Exhibit GLG-2 sets forth the development of the PPFAC base factors. Page 1 of Exhibit GLG-2 summarizes the recoverable fuel and purchased power costs by resource for MEC, SSVEC and the all-requirements members and calculates the fuel and purchased power base rate factors for each resource and member. On this page, the PPFAC bases for Base Resources are set forth on line 4, the PPFAC bases for Other Existing Resources are set forth on line 9 and the PPFAC bases for Additional ARM Resources are set forth on line 14. The average costs of fuel and purchased power from all resources are provided on line 19.

Exhibit GLG-2, page 2 summarizes the energy costs and credits from all resources. As indicated on lines 2 through 7, there are fuel costs associated with sales to tariff load and sales to third parties, as well as costs and credits associated with transfers among the AEPCO members. Also included as recoverable costs are purchased power expenses (account 555) and the costs of firm and non-firm transmission of electricity by others (account 565). Because AEPCO is able to make sales to non-members from Base Resources and Other Existing Resources, the revenue derived from such sales, as shown on lines 21 through 24, is available to reduce the costs of fuel and purchased power that must be recovered from Class A Members.

Pages 3, 4 and 5 of Exhibit GLG-2 set forth the development of energy costs and credits for Base Resources, Other Existing Resources and Additional ARM Resources, respectively, for MEC, SSVEC and the all-requirements members. All information used to develop the bases are provided in and derived from Schedules G-2 and G-6 of AEPCO's rate filing package.

Q. In your opinion, do the rates proposed by AEPCO properly and reasonably reflect the costs of providing service?

A. Yes, they do. The rates have been designed based upon the costs of providing service. The proposed rates also reflect carefully considered input from and the collective thinking of the Class A members after extensive discussion and numerous meetings. The rates, and the underlying cost structure, are the result of an objective and well-reasoned analysis of cost functions and classifications. The functionalization of costs into Base Resources, Other Existing Resources and Additional ARM Resources allows the proposed rates to directly link the functional cost drivers to the resulting costs. For the most part, costs are functionalized on a direct assignment basis: fuel costs from base units are assigned to Base Resources; operation and maintenance expenses of other generation resources are assigned to Other Existing Resources; and purchased power costs attributable to all-requirements members' demands are directly assigned to Additional ARM Resources. Joint and common costs, which by their nature cannot be directly assigned, are allocated to functions using standard, commonly employed and accepted methodologies and/or methods prescribed by member operating agreement.

Similarly, the classification of costs to Fixed, O&M and Energy functions recognizes and closely follows cost causation principles and accepted industry practices. In my opinion, the results of the cost allocations set forth in Schedule G are accurate and reasonable and the rates developed from these costs properly and reasonably reflect the costs of providing service by AEPCO.

Q. In your opinion, are the rates proposed by AEPCO fair and reasonable?

A. Yes, they are. The proposed rates accurately reflect the costs of providing service. As such, they are neither discriminatory nor burdensome upon the Members paying the rates. Members who cause costs to be incurred bear the responsibility of those costs. The underlying logic of the rate design is consistent with generally accepted ratemaking principles. Therefore, I recommend that the rates proposed by AEPCO be approved.

Q. Does this conclude your direct testimony?

A. Yes, it does.

QUALIFICATIONS AND EXPERIENCE

I graduated from the University of Arkansas at Fayetteville in 1974 with a Bachelor of Science degree in Public Administration. In 1980, I received a Master of Business Administration degree from Saint Edward's University in Austin, Texas. Upon graduation from the University of Arkansas, I was employed by the Arkansas Public Service Commission and held several positions with the Arkansas Public Service Commission staff, including Chief of the Rates Section and Interim Chief of the Finance Section. My activities in these positions included developing and presenting staff analyses and testimony concerning cost allocation studies and rate design for electric, natural gas, water, and telephone utilities; ensuring utility compliance with Arkansas Public Service Commission rate and tariff requirements; and providing supervision and management to staff financial analysts in the determination of utility cost of capital and capital structure.

In 1978, I accepted the position of Manager of Electric and Water Rates in the Economic Research Division of the Public Utility Commission of Texas. In this capacity, I was responsible for staff analyses, testimony, and activities concerning cost analysis, rate design, pricing strategies, tariffs, and econometric applications for regulated utilities.

In 1980, I was employed by Gilbert Associates, Inc. as a Management Consultant. I was promoted to Senior Management Consultant in March 1981 and to Principal Management Consultant in July 1981. In July 1981, I became Manager of Cost and Load Analysis in Gilbert Associates' Austin office. My responsibilities at this consulting firm included the duties and areas of expertise previously described, as well as management of projects and project teams working on behalf of utility clients.

I became a principal at Management Applications Consulting, ("MAC") at the time of its formation in May 1984. My experience at MAC included continued work in the electric and gas utility industry representing investor-owned utilities, electric cooperatives, and municipally-owned utility systems. My duties at MAC included the duties and areas of expertise described above. I remained a principal at MAC from May 1984 until January 2006.

From January 2006 through March 2007, I was employed as a management consultant by R. J. Covington Consulting, LLC. While employed by this firm, I continued to provide consulting services similar to those previously described as well as work in the areas of business valuation, affiliate transactions, and revenue requirement adjustments in regulatory proceedings.

In April 2007 I returned to MAC as a managing consultant. My responsibilities and job duties at MAC are the same as those previously described.

I have previously submitted testimony before the Public Service Commission of the State of Montana, the Public Utility Commission of Texas, the Arkansas Public Service Commission, the Louisiana Public Service Commission, the Railroad Commission of Texas, the Public Service Commission of Wyoming, the North Carolina Utilities Commission, and the New Hampshire Public Utilities Commission. In addition, I have provided formal rate presentations to a number of municipally-owned and cooperative electric utilities. I am currently, or have in the past, been a member of the following organizations: Association of Energy Economics, Association of Energy Engineers, Association of Energy Services Professionals, American Statistical Association, NARUC Committee on Utility Billing Practices (past member), and the NARUC Ad Hoc Committee on Section 133 of PURPA (past member). During the past 34 years, I have made a number of presentations at various industry associations and trade groups.

EXHIBIT GLG-2

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER
SUMMARY OF RESOURCE ENERGY COSTS AND BASE FUEL FACTORS

LINE NO.	DESCRIPTION	TOTAL	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Base Resources				
2	Recoverable Fuel Costs	$76,185,028	$26,137,724	$24,643,426	$25,403,878
3	kWh Sales	2,282,789,101	784,700,545	738,282,902	759,805,654
4	Base Rate Fuel Factor	$0.033374	$0.033309	$0.033379	$0.033435
5					
6	Other Existing Resources				
7	Recoverable Fuel Costs	$24,347,239	$6,804,886	$8,455,486	$9,086,868
8	kWh Sales	318,474,678	90,679,515	108,755,098	119,040,065
9	Base Rate Fuel Factor	$0.076450	$0.075043	$0.077748	$0.076335
10					
11	Additional ARM Resources				
12	Recoverable Fuel Costs	$1,973,944	$0	$0	$1,973,944
13	kWh Sales	3,200,000	0	0	3,200,000
14	Base Rate Fuel Factor	$0.616857	$0.000000	$0.000000	$0.616857
15					
16	Total Resources				
17	Recoverable Fuel Costs	$102,506,211	$32,942,611	$33,098,912	$36,464,689
18	kWh Sales	2,604,463,779	875,380,060	847,038,000	882,045,719
19	Base Rate Fuel Factor	$0.039358	$0.037632	$0.039076	$0.041341

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER
RESOURCE ENERGY COSTS AND CREDITS - ALL RESOURCES

LINE NO.	DESCRIPTION	TOTAL	BASE RESOURCES	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	Resource Costs for Member Use	$67,096,874	$56,632,134	$10,464,740	$0
2	Plus:				
3	Resource Costs for Tariff Load	$19,329,841	$19,329,841	$0	$0
4	Resource Costs for Resource Transfers	2,844,341	1,145,169	1,699,172	0
5	Resource Costs of Third Party Sales	2,507,121	2,507,121	0	0
6	Resource Transfer Credits	(1,699,172)	(1,699,172)	0	0
7	Subtotal	$22,982,131	$21,282,959	$1,699,172	$0
8					
9	Total Resource Costs - Fuel Expense Accounts 501 and 547	$90,079,005	$77,915,093	$12,163,912	$0
10					
11	Plus:				
12	Purchased Power Account 555 - Demand	$4,066,417	$1,701,090	$0	$2,365,328
13	Purchased Power Account 555 - Energy	12,478,964	751,678	11,492,376	234,910
14	Subtotal	$16,545,381	$2,452,768	$11,492,376	$2,600,238
15					
16	Plus:				
17	Non-Firm Transmission of Electricity by Others Account 565	$2,880	$2,880	$0	$0
18	Firm Transmission of Electricity by Others Account 565	4,499,040	3,198,060	1,138,980	162,000
19	Subtotal	$4,501,921	$3,200,940	$1,138,980	$162,000
20					
21	Less:				
22	Firm Contract Revenues (Energy-Related)	($2,448,992)	($2,448,992)	$0	$0
23	Resource Economy Energy	(3,952,272)	(3,504,243)	(448,029)	0
24	Firm Contract Revenues (Demand-Related)	(1,430,539)	(1,430,539)	0	0
25	Scheduling Revenues	(788,294)	0	0	(788,294)
26	Subtotal	($8,620,097)	($7,383,774)	($448,029)	($788,294)
27					
28	Recoverable Resource Fuel Costs for FPPCA	$102,506,211	$76,185,028	$24,347,239	$1,973,944
29	Recoverable Resource Fuel Costs per kWh	$0.039358	$0.033374	$0.076450	$0.616857
30					
31	kWh Purchased by Class A Member by Resource Type	2,604,463,779	2,282,789,101	318,474,678	3,200,000

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

DEVELOPMENT OF BASE RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	BASE RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Base Coal Costs for Member Use	$56,632,134	$19,467,093	$18,315,549	$18,849,492
2	Plus:				
3	Coal Costs for Tariff Load	$19,329,841	$6,678,640	$6,187,018	$6,464,183
4	Coal Costs for Resource Transfers	1,145,169	398,862	269,962	476,345
5	Coal Costs of Third Party Sales	2,507,121	1,199,603	705,665	601,853
6	Resource Transfer Credits	(1,699,172)	(572,118)	(405,130)	(721,924)
7	Subtotal	$21,282,959	$7,704,987	$6,757,515	$6,820,457
8					
9		$77,915,093	$27,172,080	$25,073,064	$25,669,949
10	Plus:				
11	Purchased Power Account 555 - Energy	$1,701,090	$584,744	$550,154	$566,192
12	Purchased Power Account 555 - Demand	751,678	269,101	238,282	244,295
13	Subtotal	$2,452,768	$853,844	$788,436	$810,488
14					
15	Plus:				
16	Non-Firm Transmission of Electricity by Others Account 565	2,880	990	932	959
17	Firm Transmission of Electricity by Others Account 565	3,198,060	1,144,905	1,013,785	1,039,369
18	Subtotal	$3,200,940	$1,145,896	$1,014,717	$1,040,328
19					
20	Total Fuel, Purchased Power and Wheeling Costs	$83,568,802	$29,171,819	$26,876,217	$27,520,765
21					
22	Less:				
23	Firm Contract Revenues (Energy-Related)	($2,448,992)	($841,832)	($792,035)	($815,125)
24	Base Resource Economy Energy	(3,504,243)	(1,680,130)	(987,275)	(836,838)
25	Firm Contract Revenues (Demand-Related	(1,430,539)	(512,133)	(453,481)	(464,925)
26	Subtotal	($7,383,774)	($3,034,095)	($2,232,791)	($2,116,888)
27					
28	Base Resource Recoverable Fuel Costs for FPPCA	$76,185,028	$26,137,724	$24,643,426	$25,403,878
29	Base Resource Recoverable Fuel Costs per kWh	$0.033374	$0.033309	$0.033379	$0.033435
30					
31	Base kWh Purchased by Class A Member	2,282,789,101	784,700,545	738,282,902	759,805,654
32	ACP Ratio	100.00%	35.80%	31.70%	32.50%

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

DEVELOPMENT OF OTHER EXISTING RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	OTHER EXISTING RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Fuel Expense Account 547	$10,464,740	$2,979,633	$3,573,577	$3,911,530
2	Plus:				
3	Purchased Power Account 555 - Demand	0	0	0	0
4	Purchased Power Account 555 - Energy	11,492,376	3,272,232	3,924,502	4,295,642
5	Subtotal	$11,492,376	$3,272,232	$3,924,502	$4,295,642
6					
7	Plus:				
8	Other Existing Resource Costs for Resource Transfers	$1,699,172	$272,834	$749,346	$676,992
9					
10	Plus:				
11	Non-Firm Transmission of Electricity by Others Account 565	$0	$0	$0	$0
12	Firm Transmission of Electricity by Others Account 565	1,138,980	407,755	361,057	370,169
13	Subtotal	$1,138,980	$407,755	$361,057	$370,169
14					
15	Total Fuel, Purchased Power and Wheeling Costs	$24,795,268	$6,932,454	$8,608,482	$9,254,333
16					
17	Less:				
18	Firm Contract Revenues (Energy-Related)	$0	$0	$0	$0
19	OER Economy Energy	(448,029)	(127,568)	(152,996)	(167,465)
20	Subtotal	($448,029)	($127,568)	($152,996)	($167,465)
21					
22	Other Existing Resource Recoverable Fuel Costs for FPPCA	$24,347,239	$6,804,886	$8,455,486	$9,086,868
23	Other Existing Resource Recoverable Fuel Costs per kWh	$0.076450	$0.075043	$0.077748	$0.076335
24					
25	Other Resource kWh Purchased by Class A Member	318,474,678	90,679,515	108,755,098	119,040,065

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

DEVELOPMENT OF ADDITIONAL ARM RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	ADDITIONAL ARM RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Purchased Power Account 555 - Demand	$2,365,328	$0	$0	$2,365,328
2	Purchased Power Account 555 - Energy	234,910	0	0	234,910
3	Subtotal	$2,600,238	$0	$0	$2,600,238
4					
5	Plus:				
6	Non-Firm Transmission of Electricity by Others Account 565	$0	$0	$0	$0
7	Firm Transmission of Electricity by Others Account 565	162,000	0	0	$162,000
8	Subtotal	$162,000	$0	$0	$162,000
9					
10	Total Fuel, Purchased Power and Wheeling Costs	$2,762,238	$0	$0	$2,762,238
11					
12	Less:				
13	Firm Contract Revenues (Energy-Related)	$0	$0	$0	0
14	Additional ARM Economy Energy	0	0	0	0
15	Scheduling Revenues	(788,294)	0	0	(788,294)
16	Subtotal	($788,294)	$0	$0	($788,294)
17					
18	Additional ARM Resource Recoverable Fuel Costs for FPPCA	$1,973,944	$0	$0	$1,973,944
19	Additional Resource Recoverable Fuel Costs per kWh	$0.616857	$0.000000	$0.000000	$0.616857
20					
21	Additional ARM kWh Purchased by Class A Member	3,200,000	0	0	3,200,000

EXHIBIT
A-7
ADMITTED

SUPPLEMENTAL DIRECT TESTIMONY OF GARY L. GOBLE ON BEHALF OF ARIZONA ELECTRIC POWER COOPERATIVE, INC.

I. INTRODUCTION

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

A. My name is Gary L. Goble. I am a managing consultant with the firm of Management Applications Consulting, Inc. ("MAC"). MAC's primary office is 1103 Rocky Drive, Suite 201, Reading, Pennsylvania 19609. My office is located at 11405 Cezanne Court, Austin, Texas 78726.

Q. Are you the same Gary L. Goble who filed direct testimony and exhibits in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Supplemental Direct Testimony?

A. As explained in the Supplemental Direct Testimony of Mr. Pierson, AEPCO and its Class A Members have reached an agreement on several issues which had not been resolved at the time AEPCO filed its rate application on October 1, 2009 (the "Agreement"). As a result of the Agreement, AEPCO is making five primary revisions to its revenue requirement request, cost allocations and rates initially proposed in this proceeding. The purpose of my Supplemental Direct Testimony is to describe how several of these adjustments affect the cost-of-service study and the proposed rates in Schedules G and H and the calculation of the Purchased

Power and Fuel Adjustment Clause ("PPFAC") bases provided in my original filed Exhibit GLG-2.

Q. Please identify the revised schedules and exhibit that you are sponsoring in relation to the amended application.

A. I am sponsoring the amended and restated G and H Schedules and Exhibit GLG-3, which is a revised version of my original Exhibit GLG-2. Schedules G-1 through G-7 provide AEPCO's revised cost-of-service study and rate design consistent with the Agreement. Schedules H-1 through H-5 provide corresponding proof of revenue, billing determinant information, revenue detail and customer impact information for each of AEPCO's six Class A member cooperatives. Exhibit GLG-3 provides the calculation of the PPFAC bases consistent with the Agreement.

II. REVISIONS TO THE ALLOCATED COST-OF-SERVICE

Q Please describe the components of the Agreement that affect the calculations and the results of the allocated cost-of-service study.

A. As discussed in Mr. Pierson's testimony, AEPCO is withdrawing the mercury control expense adjustment and, as well, AEPCO and the members have agreed to a reduction in the requested level of margins. I have incorporated these revisions into the cost-of-service study. The parties have also agreed to shift Scheduling Revenues from the Additional ARM Resources O&M function to the Base

1 Resources fixed cost function and the parties have agreed to a shift of resource
2 planning expenses from Base Resources O&M to Additional ARM O&M.
3
4 **Q. Are there any other possible outcomes of AEPCO's and its members'**
5 **discussions that may impact AEPCO's rates?**
6 **A.** Yes, in addition to these changes, AEPCO and its Class A Members need to
7 consider the impact on rates that will occur once Trico Electric Cooperative, Inc.
8 ("Trico") becomes a Partial-Requirements Member ("PRM"). The outcome of
9 the discussions on this issue and the resulting rates will be provided in
10 conjunction with the filing of the amended contracts.
11
12 **Q. Please describe the revisions you have made to Schedules G-1 through G-7,**
13 **AEPCO's allocated cost-of-service study, to reflect the changes.**
14 A. Because the cost-of-service schedules are designed with the summary at the
15 beginning and the more detailed schedules toward the end, I will begin with a
16 description of the changes made to Schedule G-7 and progress toward a
17 description of Schedule G-1.
18 Schedule G-6, page 5, has been revised to reflect a change in the functionalization
19 of Scheduling Revenues from the Additional ARM O&M function to the Base
20 Resource Fixed function as previously described. There were no changes to
21 Schedule G-6, pages 3 and 4. Schedule G-6, page 2, has been revised to reflect
22 the shift of Administrative and General expense of $157,723 associated with
23 resource planning expenses from the Base Resources category of costs to the

Additional ARM Resources category of costs. There are no changes to Schedule G-6, page 1, or to Schedule G-5, page 1.

On Schedule G-4, page 1, the fixed and O&M charges for the ARMs have been decoupled from billing demands and have been set at fixed (i.e., non-varying) monthly amounts. This rate structure is consistent with that of AEPCO's two PRMs. No changes were made to Schedules G-1 through G-3, although the changes described above flow through these Schedules.

III. REVISIONS TO THE PROPOSED RATES

Q. Please describe the revisions that were made to Schedules H-1 through H-5, the revenue and billing determinant schedules.

A. The fixed charges, O&M charges and energy charges resulting from the Agreement are as follows:

Charges	MEC	SSVEC	ARM
Fixed Charge	$709,721	$628,440	$862,343
O&M Charge	$1,323,724	$1,172,125	$1,229,653
Base Energy Charge	$0.03216/kWh	$0.03230/kWh	$0.03236/kWh
Other Existing Resources Charge	$0.06879/kWh	$0.06676/kWh	$0.06746/kWh
Additional ARM Resources Charge	N/A	N/A	N/A

The Agreement resulted in the elimination of per-unit demand charges for both the PRMs and ARMs. Specifically, the current demand charge for the PRMs has been replaced with a fixed charge and results in a rate design that now consists of two fixed charges. The current demand charge for the ARMs has been eliminated

and replaced with two fixed charges, which is consistent with the rate design for the PRMs.

The Agreement also specifies that each individual ARM's monthly billing will be based on each ARM's proportionate share of the total ARMs' fixed and O&M charges shown in the table above. Each ARM's proportionate share of the total will be calculated according to the ratio of each individual ARM's current 12-month rolling average coincident demand to the sum of the ARMs' current 12-month rolling average coincident demands (i.e., Demand Share Ratio). The development of each ARM's Demand Share Ratio is set forth on line 5 of Amended and Restated Schedule H-2, pages 13, 14, 15 and 18. Each ARM's Fixed Charge and Fixed O&M Charge is set forth on lines 33 and 34 of the same pages. The separate energy charges for Other Existing Resources and Additional ARM Resources proposed in AEPCO's original filing have been combined in this Amended and Restated filing and are set forth on line 28 of these schedules. The results of the changes AEPCO proposes are provided in Amended and Restated Schedule H-2, page 1.

IV. REVISIONS TO THE PROPOSED PPFAC BASES

Q. Please explain Exhibit GLG-3, which provides the calculation of the PPFAC bases.

A. Exhibit GLG-3 provides the revised calculation of the PPFAC bases taking into account the changes previously described. In addition, I have combined the ARM

PPFAC bases for Other Existing Resources and Additional ARM Resources that AEPCO proposed in its original filing.

Q. Why have you combined the PPFAC base energy costs for the ARM Other Existing Resources and Additional ARM Resources?

A. Because of the relatively high fixed costs (i.e., demand charges) associated with the small amount of power taken by AEPCO under the Southpoint and Griffith purchased power contracts, the cost per kWh for Additional ARM Resources is abnormally high and is not likely to reflect the average costs per kWh that would occur if and when additional ARM resources are acquired. In order to prevent a potentially large difference between the originally proposed Additional ARM PPFAC base and the average cost of future Additional ARM Resources, the costs and kWh of Additional ARM Resources are being combined with the ARM's allocated portion of Other Existing Resources costs and kWh to avoid this potential problem. This will produce a "blended" PPFAC base for the ARMs which will be comprised of Other Existing Resources and Additional ARM Resources. This blended PPFAC base is shown on Exhibit GLG-3, page 1, line 19.

IV. CONCLUSION

Q. Are the allocation of costs and the proposed rate design reached in the Agreement fair and reasonable?

A. Yes. The allocation of costs and the design of the proposed rates are fair and reasonable. I recommend that the proposed cost-of-service study and proposed rates set forth in the Amended and Restated G and H Schedules as well as the PPFAC bases set forth in Exhibit GLG-3 be approved.

Q. Does this conclude your Supplemental Direct Testimony?

A. Yes, it does.

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

SUMMARY OF RESOURCE ENERGY COSTS AND BASE FUEL FACTORS

LINE NO.	DESCRIPTION	TOTAL	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Base Resources				
2	Recoverable Fuel Costs	$76,185,028	$26,137,724	$24,643,426	$25,403,878
3	kWh Sales	2,282,789,101	784,700,545	738,282,902	759,805,654
4	Base Rate Fuel Factor	$0.033374	$0.033309	$0.033379	$0.033435
5					
6	Other Existing Resources				
7	Recoverable Fuel Costs	$24,347,239	$6,804,886	$8,455,486	$9,086,868
8	kWh Sales	318,474,678	90,679,515	108,755,098	119,040,065
9	Base Rate Fuel Factor	$0.076450	$0.075043	$0.077748	$0.076335
10					
11	Additional ARM Resources				
12	Recoverable Fuel Costs	$2,762,238	$0	$0	$2,762,238
13	kWh Sales	3,200,000	0	0	3,200,000
14	Base Rate Fuel Factor	$0.863199	$0.000000	$0.000000	$0.863199
15					
16	OER and Add ARM Resources Combined				
17	Recoverable Fuel Costs	$27,109,477	$6,804,886	$8,455,486	$11,849,105
18	kWh Sales	321,674,678	90,679,515	108,755,098	122,240,065
19	Base Rate Fuel Factor	$0.084276	$0.075043	$0.077748	$0.096933
20					
21	Total Resources				
22	Recoverable Fuel Costs	$103,294,505	$32,942,611	$33,098,912	$37,252,983
23	kWh Sales	2,604,463,779	875,380,060	847,038,000	882,045,719
24	Base Rate Fuel Factor	$0.039661	$0.037632	$0.039076	$0.042235

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER
RESOURCE ENERGY COSTS AND CREDITS - ALL RESOURCES

LINE NO.	DESCRIPTION	TOTAL	BASE RESOURCES	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	Resource Costs for Member Use	$67,096,874	$56,632,134	$10,464,740	$0
2	Plus:				
3	Resource Costs for Tariff Load	$19,329,841	$19,329,841	$0	$0
4	Resource Costs for Resource Transfers	2,844,341	1,145,169	1,699,172	0
5	Resource Costs of Third Party Sales	2,507,121	2,507,121	0	0
6	Resource Transfer Credits	(1,699,172)	(1,699,172)	0	0
7	Subtotal	$22,982,131	$21,282,959	$1,699,172	$0
8					
9	Total Resource Costs - Fuel Expense Accounts 501 and 547	$90,079,005	$77,915,093	$12,163,912	$0
10					
11	Plus:				
12	Purchased Power Account 555 - Demand	$4,066,417	$1,701,090	$0	$2,365,328
13	Purchased Power Account 555 - Energy	12,478,964	751,678	11,492,376	234,910
14	Subtotal	$16,545,381	$2,452,768	$11,492,376	$2,600,238
15					
16	Plus:				
17	Non-Firm Transmission of Electricity by Others Account 565	$2,880	$2,880	$0	$0
18	Firm Transmission of Electricity by Others Account 565	4,499,040	3,198,060	1,138,980	162,000
19	Subtotal	$4,501,921	$3,200,940	$1,138,980	$162,000
20					
21	Less:				
22	Firm Contract Revenues (Energy-Related)	($2,448,992)	($2,448,992)	$0	$0
23	Resource Economy Energy	(3,952,272)	(3,504,243)	(448,029)	0
24	Firm Contract Revenues (Demand-Related)	(1,430,539)	(1,430,539)	0	0
25	Scheduling Revenues	0	0	0	0
26	Subtotal	($7,831,803)	($7,383,774)	($448,029)	$0
27					
28	Recoverable Resource Fuel Costs for FPPCA	$103,294,505	$76,185,028	$24,347,239	$2,762,238
29	Recoverable Resource Fuel Costs per kWh	$0.039661	$0.033374	$0.076450	$0.863199
30					
31	kWh Purchased by Class A Member by Resource Type	2,604,463,779	2,282,789,101	318,474,678	3,200,000

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

DEVELOPMENT OF BASE RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	BASE RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Base Coal Costs for Member Use	$56,632,134	$19,467,093	$18,315,549	$18,849,492
2	Plus:				
3	Coal Costs for Tariff Load	$19,329,841	$6,678,640	$6,187,018	$6,464,183
4	Coal Costs for Resource Transfers	1,145,169	398,862	269,962	476,345
5	Coal Costs of Third Party Sales	2,507,121	1,199,603	705,665	601,853
6	Resource Transfer Credits	(1,699,172)	(572,118)	(405,130)	(721,924)
7	Subtotal	$21,282,959	$7,704,987	$6,757,515	$6,820,457
8					
9		$77,915,093	$27,172,080	$25,073,064	$25,669,949
10	Plus:				
11	Purchased Power Account 555 - Energy	$1,701,090	$584,744	$550,154	$566,192
12	Purchased Power Account 555 - Demand	751,678	269,101	238,282	244,295
13	Subtotal	$2,452,768	$853,844	$788,436	$810,488
14					
15	Plus:				
16	Non-Firm Transmission of Electricity by Others Account 565	2,880	990	932	959
17	Firm Transmission of Electricity by Others Account 565	3,198,060	1,144,905	1,013,785	1,039,369
18	Subtotal	$3,200,940	$1,145,896	$1,014,717	$1,040,328
19					
20	Total Fuel, Purchased Power and Wheeling Costs	$83,568,802	$29,171,819	$26,876,217	$27,520,765
21					
22	Less:				
23	Firm Contract Revenues (Energy-Related)	($2,448,992)	($841,832)	($792,035)	($815,125)
24	Base Resource Economy Energy	(3,504,243)	(1,680,130)	(987,275)	(836,838)
25	Firm Contract Revenues (Demand-Related)	(1,430,539)	(512,133)	(453,481)	(464,925)
26	Subtotal	($7,383,774)	($3,034,095)	($2,232,791)	($2,116,888)
27					
28	Base Resource Recoverable Fuel Costs for FPPCA	$76,185,028	$26,137,724	$24,643,426	$25,403,878
29	Base Resource Recoverable Fuel Costs per kWh	$0.033374	$0.033309	$0.033379	$0.033435
30					
31	Base kWh Purchased by Class A Member	2,282,789,101	784,700,545	738,282,902	759,805,654
32	ACP Ratio	100.00%	35.80%	31.70%	32.50%

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

DEVELOPMENT OF OTHER EXISTING RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	OTHER EXISTING RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Fuel Expense Account 547	$10,464,740	$2,979,633	$3,573,577	$3,911,530
2	Plus:				
3	Purchased Power Account 555 - Demand	0	0	0	0
4	Purchased Power Account 555 - Energy	11,492,376	3,272,232	3,924,502	4,295,642
5	Subtotal	$11,492,376	$3,272,232	$3,924,502	$4,295,642
6					
7	Plus:				
8	Other Existing Resource Costs for Resource Transfers	$1,699,172	$272,834	$749,346	$676,992
9					
10	Plus:				
11	Non-Firm Transmission of Electricity by Others Account 565	$0	$0	$0	$0
12	Firm Transmission of Electricity by Others Account 565	1,138,980	407,755	361,057	370,169
13	Subtotal	$1,138,980	$407,755	$361,057	$370,169
14					
15	Total Fuel, Purchased Power and Wheeling Costs	$24,795,268	$6,932,454	$8,608,482	$9,254,333
16					
17	Less:				
18	Firm Contract Revenues (Energy-Related)	$0	$0	$0	$0
19	OER Economy Energy	(448,029)	(127,568)	(152,996)	(167,465)
20	Subtotal	($448,029)	($127,568)	($152,996)	($167,465)
21					
22	Other Existing Resource Recoverable Fuel Costs for FPPCA	$24,347,239	$6,804,886	$8,455,486	$9,086,868
23	Other Existing Resource Recoverable Fuel Costs per kWh	$0.076450	$0.075043	$0.077748	$0.076335
24					
25	Other Resource kWh Purchased by Class A Member	318,474,678	90,679,515	108,755,098	119,040,065

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

DEVELOPMENT OF ADDITIONAL ARM RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	ADDITIONAL ARM RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS
1	Purchased Power Account 555 - Demand	$2,365,328	$0	$0	$2,365,328
2	Purchased Power Account 555 - Energy	234,910	0	0	234,910
3	Subtotal	$2,600,238	$0	$0	$2,600,238
4					
5	Plus:				
6	Non-Firm Transmission of Electricity by Others Account 565	$0	$0	$0	$0
7	Firm Transmission of Electricity by Others Account 565	162,000	0	0	162,000
8	Subtotal	$162,000	$0	$0	$162,000
9					
10	Total Fuel, Purchased Power and Wheeling Costs	$2,762,238	$0	$0	$2,762,238
11					
12	Less:				
13	Firm Contract Revenues (Energy-Related)	$0	$0	$0	$0
14	Additional ARM Economy Energy	0	0	0	0
15	Scheduling Revenues	0	0	0	0
16	Subtotal	$0	$0	$0	$0
17					
18	Additional ARM Resource Recoverable Fuel Costs for FPPCA	$2,762,238	$0	$0	$2,762,238
19	Additional Resource Recoverable Fuel Costs per kWh	$0.863199	$0.000000	$0.000000	$0.863199
20					
21	Additional ARM kWh Purchased by Class A Member	3,200,000	0	0	3,200,000

EXHIBIT

A-8

~~ADMITTED~~

REBUTTAL TESTIMONY OF GARY L. GOBLE

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

August 30, 2010

10421-59/2531555

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1 **REBUTTAL TESTIMONY OF GARY L. GOBLE**

2 **ON BEHALF OF**

3 **ARIZONA ELECTRIC POWER COOPERATIVE, INC.**

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

5 A. My name is Gary L. Goble. I am a consultant with the firm of Management
6 Applications Consulting, Inc. ("MAC"). MAC's primary office is 1103 Rocky Drive,
7 Suite 201, Reading, Pennsylvania 19609. My office is located at 11405 Cezanne Court,
8 Austin, Texas 78726.

9 **Q. Are you the same Gary L. Goble who submitted Direct Testimony and**
10 **Supplemental Direct Testimony on behalf of Arizona Electric Power Cooperative,**
11 **Inc. ("AEPCO")?**

12 A. Yes, I am.

13 **Q. What is the purpose of your Rebuttal Testimony?**

14 A. Its primary purpose is to present revised G and H Schedules, which are attached hereto
15 as GLG Schedules G-1 through G-7 and GLG Schedules H-1 through H-5. These
16 revised schedules incorporate the Utilities Division ("Staff") proposed allocations and
17 adjustments described in the Direct Testimony of Dennis M. Kalbarczyk as well as the
18 adjustments discussed in the Rebuttal Testimony of AEPCO witness Gary E. Pierson.

1 **Q. Did Staff witness Kalbarcyzk agree with the methods and processes employed in**

2 **AEPCO's initial filing and in its amended and restated filing?**

3 A. Yes. Mr. Kalbarcyzk stated the following at page 9, lines 9-12, of his Direct

4 Testimony:

> 5 I believe that AEPCO's amended fully allocated cost of service
> 6 methods, including the underlying process and methods described and
> 7 significant input from its members appear to be a reasonable basis for
> 8 the development of the fully allocated cost of service study and rate
> 9 design.

10 In addition, also on page 9 at lines 16-21, Mr. Kalbarcyzk commented:

> 11 I reviewed the methods used to develop the underlying allocation
> 12 factors, and I examined the allocated costs that resulted from the
> 13 application of these factors to the amended revenue requirement
> 14 elements for each rate-design component proposed by AEPCO. This
> 15 review confirmed that the methods and approach here were reasonable
> 16 and appropriately reflected in the amended filing.

17 **Q. Did you use these same methods and processes in preparing GLG Schedules G**

18 **and H which you are presenting with your Rebuttal Testimony?**

19 A. Yes, I did.

20 **Q. Please describe the categories of changes you have made to the amended and**

21 **restated Schedules G and H that were filed with AEPCO's amended and restated**

22 **application on April 20, 2010.**

23 A. Because AEPCO is agreeing to Staff's expense adjustments as proposed by Mr. Smith,

24 my revisions reflect those adjustments which were discussed at pages 10-11 of

25 Mr. Kalbarczyk's Direct Testimony. Second, I have adjusted AEPCO's proposed rates

26 to provide for an overall reduction of $1,172,317, as described in Mr. Pierson's

Rebuttal Testimony and his Exhibit GEP-2, instead of the $231,014 revenue increase recommended by Staff. Finally, the revised schedules reflect Trico Electric Cooperative's ("Trico") transition from an all-requirement member ("ARM") to a partial-requirements member ("PRM") and assign costs accordingly.

Q. Please describe the methodology you used to separate the costs of serving Trico as a PRM.

A. As discussed at pages 5-6 of Mr. Pierson's Supplemental Direct Testimony, Trico has elected to convert its Class A Member relationship with AEPCO from an ARM to a PRM. Consequently, I have identified and separated Trico's costs from the cost-of-service of the other three ARMs[1] (who are referenced herein as "Collective All-Requirements Members" or "CARMs"). Specifically, I utilized Trico's contractual Allocated Capacity Percentage ("ACP") of 21.1% to determine Trico's cost responsibility for Base Fixed and O&M costs and Other Existing Resources Fixed and O&M costs. Similarly, I utilized Trico's contractual ACP in comparison to the total of Trico and the CARMs' ACPs to determine Trico's cost responsibility for the non-energy-related portion of the Additional ARM Resources (the Griffith and South Point purchased power contracts).

[1] After the Trico conversion, the three remaining ARMs will be Anza Electric Cooperative, Inc., Duncan Valley Electric Cooperative, Inc. and Graham County Electric Cooperative, Inc.

1 **Q. Please describe the revisions reflected in GLG Schedules G-1 through G-7,**
2 **AEPCO's allocated cost-of-service study.**
3 A. Because the cost-of-service schedules are designed with the summary at the beginning
4 and the more detailed schedules toward the end, I will begin with a description of the
5 changes reflected in GLG Schedule G-7 and move toward GLG Schedule G-1.

6 Because the Billing Unit Model used to develop the Base Resources kWh, Other
7 Existing Resources kWh and Additional ARM Resources kWh does not yet reflect
8 Trico as a separate load entity for cost-of-service purposes, it was necessary to estimate
9 Trico's portion of the ARM kWh on a pro-rata basis. Accordingly, GLG Schedule G-7
10 includes two additional columns—one labeled "TRICO PRM" and the other
11 "CARMs." These columns divide the figures in the original ARM column (which
12 included Trico's costs as an ARM) to separate Trico's estimated costs as a PRM from
13 the remaining three CARMs. Given that Trico's adjusted test year sales were about
14 73% of the total annual kWh sales to the ARMs, Trico's Base Resources kWh and its
15 Other Existing Resources kWh were estimated to be approximately 73% of the ARMs'
16 combined kWh in those categories, while the remaining approximate 27% was assigned
17 to the CARMs. These kWh allocations are shown on lines 3-5 of GLG Schedule G-7.

18 GLG Schedule G-6, page 5, reflects AEPCO's proposed margins of $2,947,420. GLG
19 Schedule G-6, page 4, is unchanged from the schedule submitted in April. GLG
20 Schedule G-6, pages 3, 3.1, 3.2 and 3.3, incorporates Mr. Kalbarczyk's allocation of
21 Staff's revenue requirement adjustments. GLG Schedule G-6, page 2, remains

unchanged. GLG Schedule G-6, page 1, is a summary that includes the revisions described above.

GLG Schedule G-4, pages 1 and 2, also includes additional columns for the separation of costs between Trico and the remaining three CARMs. The Fixed Charge and O&M charges for Trico and the CARMs have been decoupled from billing demands and are proposed to be fixed monthly amounts.

The above-referenced changes to the G Schedules flow through to GLG Schedules G-1 and G-2. Schedules G-3 and G-5 remain inapplicable to AEPCO.

Q. Please describe the changes reflected in GLG Schedules H-1 through H-5—The Revenue and Billing Determinant Schedules.

A. As shown on GLG Schedule H-3, the Fixed and O&M demand charges per kW for Trico and the remaining three CARMs have been converted to fixed monthly amounts. Based on Trico's costs as identified in GLG Schedules G-1 through G-7, the proposed charges for Trico are a Fixed Charge of $646,435 and an O&M Charge of $764,465. The rates per billing kW have been eliminated. Trico's rates will be applied in exactly the same fashion as those of the two current PRMs (Mohave Electric Cooperative ("MEC") and Sulphur Springs Valley Electric Cooperative ("SSVEC")). The proposed CARM Fixed Charge of $238,793 and the proposed CARM O&M Charge of $414,019, also shown on GLG Schedule H-3, are allocated among the three remaining CARMs based upon each CARM's monthly Demand Ratio Share. Mr. Pierson discussed the

details of this demand rate structure at page 5 of his Supplemental Direct Testimony. The billing of the three CARMs is shown on GLG Schedule H-2, pages 5, 6 and 7, using the actual test year PPFAC (formerly FPPAC) and on GLG Schedule H-2, pages 13, 14, and 15, using the synchronized test year PPFAC. Trico's proposed rates and revenues using test year actual and synchronized PPFAC revenues are shown on GLG Schedule H-2, pages 10 and 18, respectively. MEC's rates and revenues using test year actual and synchronized PPFAC revenues are shown on GLG Schedule H-2, pages 8 and 16, respectively. SSVEC's rates and revenues using test year actual and synchronized PPFAC revenues are shown on GLG Schedule H-2, pages 9 and 17, respectively. GLG Schedule H-2, page 1, and GLG Schedule H-1 reflect the above-referenced changes. GLG Schedule H-1 also reflects AEPCO's revisions to its proposed revenue requirement. Schedules H-4 and H-5 remain inapplicable to AEPCO.

Q. Please summarize the results of incorporating the Staff and AEPCO revenue requirement adjustments and the separation of Trico from the remaining CARMs.

A. After incorporating Staff's expense adjustments and Mr. Pierson's revenue requirements recommendations, as well as modifying the allocations to separate Trico's revenue requirements as a PRM, revenue requirements and rates by function were developed. Table 1 below sets forth the proposed rates produced by these changes.

Table 1

Monthly Charges	MEC	SSVEC	TRICO	CARM
Fixed Charge	$727,283	$643,991	$646,435	$238,793
O&M Charge	$1,274,882	$1,128,876	$764,465	$414,019
Base Energy Charge	$0.03215	$0.03229	$0.03238	$0.03156
Other Existing Resources Charge	$0.06879	$0.06676	$0.06604	$0.06170

Q. Please describe the revisions you have made to the calculation of the PPFAC bases.

A. Exhibit GLG-3 incorporates separate PPFAC bases for Trico and the three remaining CARMs. Table 2 below sets forth the proposed PPFAC rates produced by these changes.

Table 2

PPFAC Base Cost per kWh	MEC	SSVEC	TRICO	CARM
Base Resources	$0.03330	$0.03337	$0.03336	$0.03361
Other Existing Resources	$0.06971	$0.07241	$0.09084*	$0.07941*

* The PPFAC Base for Trico and CARM Other Existing Resources includes Additional ARM Resources (*see* GLG-3, page 1, line 19).

Q. In your opinion, are the allocation of costs and the proposed rate design you have described fair and reasonable?

A. Yes. The allocation of costs and the design of the proposed rates are fair, reasonable and non-discriminatory. I recommend that the proposed rates set forth in GLG Schedule H-3 (summarized in Table 1 above) and the PPFAC bases set forth in Exhibit GLG-3 (summarized in Table 2 above) be approved.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Arizona Electric Power Cooperative, Inc.

COST OF SERVICE SUMMARY - PRESENT RATES

LINE NO.	DESCRIPTION	TOTAL AEPCO
1	**REVENUES:**	
2	**MEMBERS (a)**	$166,590,199
3	**NON-MEMBERS (b)**	8,620,097
4	**OTHER OPERATING REVENUE (b)**	3,523,943
5	**TOTAL REVENUES**	$178,734,239
6	**OPERATING EXPENSES (c)**	162,820,299
7	**ELECTRIC OPERATING MARGINS**	$15,913,939
8	**INCOME TAXES**	0
9	**RETURN (MARGINS) (LINE 7 - LINE 8)**	$15,913,939
10		
11	**RATE BASE (d)**	$ 211,802,594
12	**RATE OF RETURN**	7.51%
13		
14		
15	SUPPORTING SCHEDULES:	
16	(a) H-1, LINE 1	
17	(b) C-1, PAGE 3, LINES 3 AND 5	
18	(c) G-6, PAGE 1, LINE 50 AND C-1, PAGE 4, LINE 44	
19	(d) B-1, LINE 9	

Arizona Electric Power Cooperative, Inc.

COST OF SERVICE SUMMARY - PROPOSED RATES

LINE NO.	DESCRIPTION	TOTAL AEPCO
1	**REVENUES:**	
2	**MEMBERS (a)**	$165,446,321
3	**NON-MEMBERS (b)**	8,620,097
4	**OTHER OPERATING REVENUE (b)**	3,523,943
5	**TOTAL REVENUES**	$177,590,361
6	**OPERATING EXPENSES (c)**	162,820,299
7	**ELECTRIC OPERATING MARGINS**	$14,770,062
8	**INCOME TAXES**	0
9	**RETURN (MARGINS) (LINE 6 - LINE 7)**	$14,770,062
10		
11	**RATE BASE (d)**	$ 211,802,594
12	**RATE OF RETURN**	6.97%
13		
14		
15	SUPPORTING SCHEDULES:	
16	(a) H-1, LINE 1	
17	(b) C-1, PAGE 3, LINES 3 AND 5	
18	(c) G-6, PAGE 1, LINE 50 AND C-1, PAGE 4, LINE 44	
19	(d) B-1, LINE 9	

Arizona Electric Power Cooperative, Inc.

DERIVATION OF PROPOSED RATES

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1					
2		SEE SCHEDULE G-4, PAGE 1 OF 2			

Arizona Electric Power Cooperative, Inc.

RATE BASE ALLOCATION TO CLASSES OF SERVICE

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1					
2		THIS SCHEDULE IS NOT APPLICABLE			

Arizona Electric Power Cooperative, Inc.

DERIVATION OF REVENUE REQUIREMENTS AND RATES

LINE NO.	FUNCTIONAL COSTS	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO	TRICO PRM	CARM
1	REVENUE REQUIREMENT DEVELOPMENT						
2	FIXED COSTS						
3	BASE RESOURCES	$6,691,277	$5,924,957	$6,074,483	$18,690,717	$3,943,741	$2,130,742
4	OTHER EXISTING RESOURCES	2,036,124	1,802,937	1,848,437	5,687,497	1,200,062	648,375
5	ADDITIONAL ARM RESOURCES	0	0	2,699,810	2,699,810	2,613,416	86,394
6	SUB-TOTAL	$8,727,401	$7,727,894	$10,622,730	$27,078,024	$7,757,219	$2,865,510
7							
8	O&M						
9	BASE RESOURCES	$12,638,564	$11,191,130	$11,473,556	$35,303,250	$7,448,986	$4,024,571
10	OTHER EXISTING RESOURCES	2,660,026	2,355,386	2,414,828	7,430,239	1,567,780	847,047
11	ADDITIONAL ARM RESOURCES	0	0	253,422	253,422	156,816	96,606
12	SUB-TOTAL	$15,298,589	$13,546,516	$14,141,806	$42,986,911	$9,173,582	$4,968,224
13							
14	ENERGY						
15	BASE RESOURCES	$25,226,075	$23,835,642	$24,575,672	$73,637,389	$16,923,888	$7,135,531
16	OTHER EXISTING RESOURCES	6,237,567	7,259,986	8,011,534	21,509,087	7,939,980	587,806
17	ADDITIONAL ARM RESOURCES	0	0	234,910	234,910	227,393	7,517
18	SUB-TOTAL	$31,463,642	$31,095,628	$32,822,116	$95,381,386	$25,091,261	$7,730,854
19							
20	TOTAL RESOURCE COSTS						
21	BASE RESOURCES	$44,555,915	$40,951,730	$42,123,711	$127,631,356	$28,316,615	$13,290,844
22	OTHER EXISTING RESOURCES	10,933,717	11,418,308	12,274,798	34,626,823	10,707,822	2,083,228
23	ADDITIONAL ARM RESOURCES	0	0	3,188,142	3,188,142	2,997,625	190,517
24	SUB-TOTAL	$55,489,632	$52,370,038	$57,586,651	$165,446,321	$42,022,063	$15,564,588
25							
26							
27	RATE DEVELOPMENT						
28	BILLING DETERMINANTS						
29	BILLING DEMANDS	1,723,399	1,629,806	478,154	3,831,359	1,361,311	478,154
30	BASE RESOURCE KWH	784,700,545	738,282,902	759,805,654	2,282,789,101	522,616,908	226,109,971
31	OTHER EXISTING RESOURCES KWH	90,679,515	108,755,098	119,040,065	318,474,678	120,572,028	9,546,812
32	ADDITIONAL ARM RESOURCES KWH	0	0	3,200,000	3,200,000	3,097,600	102,400
33	TOTAL KWH	875,380,060	847,038,000	882,045,719	2,604,463,779	646,286,536	235,759,183
34							
35	MONTHLY CHARGES						
36	FIXED CHARGE	$727,283	$643,991	$885,227	$7.067	$646,435	$238,793
37	O&M CHARGE	$1,274,882	$1,128,876	$1,178,484	$11.220	$764,465	$414,019
38	BASE ENERGY CHARGE	$0.03215	$0.03229	$0.03234	$0.03226	$0.03238	$0.03156
39	OTHER EXISTING RESOURCE ENERGY CHARGE	$0.06879	$0.06676	$0.06746	$0.06754	$0.06604	$0.06170
40	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	$0.06746	$0.07341	$0.06604	$0.06170
41	AVERAGE ENERGY CHARGE	$0.035943	$0.036711	$0.037211	$0.036622	$0.038824	$0.032791

Arizona Electric Power Cooperative, Inc.

ASSIGNMENT OF BASE AND OTHER ENERGY RESOURCE COSTS AND CREDITS

BASE RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	ENERGY	MEC	SSVEC	ARM	TRICO PRM	CARM
1	OPERATING EXPENSES:						
2	OPERATIONS						
3	COAL COSTS FOR TARIFF LOAD	$19,329,841	$6,678,640	$6,187,018	$6,464,183	$4,265,827	$1,845,608
4	COAL COSTS FOR RESOURCE TRANSFERS	1,145,169	398,862	269,962	476,345	303,180	525,914
5	COAL COSTS FOR THIRD PARTY SALES	2,507,121	1,199,603	705,665	601,853	420,098	181,755
6	RESOURCE TRANSFER CREDITS	(1,699,172)	(572,118)	(405,130)	(721,924)	(458,487)	(779,689)
7	SUB-TOTAL	$21,282,959	$7,704,987	$6,757,515	$6,820,457	$4,530,617	$1,773,588
8							
9	BASE COST BEFORE ADJUSTMENTS	56,603,695	19,457,317	18,306,352	18,840,027	13,150,478	5,689,548
10							
11	PRODUCTION - FUEL A/C 501	$77,886,654	$27,162,304	$25,063,867	$25,660,484	$17,681,095	$7,463,137
12							
13	ADJUSTMENTS						
14	PURCHASED POWER ACCOUNT 555 - ENERGY	1,701,090	584,744	550,154	566,192	395,206	170,986
15	TRANSMISSION OF ELEC BY OTHERS ACCOUNT 565 - ENERGY	2,880	990	932	959	669	290
16	FIRM CONTRACT REVENUES	(2,448,992)	(841,832)	(792,035)	(815,125)	(568,963)	(246,162)
17	BASE RESOURCE ECONOMY ENERGY	(3,504,243)	(1,680,130)	(987,275)	(836,838)	(584,119)	(252,719)
18	SCHEDULING REVENUES	0	0	0	0	0	0
19	OTHER OPERATING REVENUES	0	0	0	0	0	0
20	TOTAL NET BASE RESOURCES ENERGY REVENUE REQUIREMENTS	$73,637,389	$25,226,075	$23,835,642	$24,575,672	$16,923,888	$7,135,531
21							
22							

OTHER RESOURCE ENERGY COSTS AND CREDITS

23							
24	DESCRIPTION	ENERGY	MEC	SSVEC	ARM	TRICO	OTHER ARM
25	OTHER EXISTING RESOURCE COSTS	$21,509,087	$6,237,567	$7,259,986	$8,011,534	$7,939,980	$587,806
26	RESOURCE TRANSFER COSTS	1,699,172	272,834	749,346	676,992	1,143,573	49,671
27	OTHER RESOURCE COSTS	$19,809,915	$5,964,733	$6,510,640	$7,334,542	$6,796,407	$538,135
28							
29	RESOURCE TRANSFER KWH	35,966,376	5,616,722	15,907,156	14,442,498	25,707,138	1,158,264
30	OTHER RESOURCE KWH	282,508,302	85,062,793	92,847,942	104,597,567	94,864,890	8,388,548
31	TOTAL OTHER EXISTING RESOURCE KWH	318,474,678	90,679,515	108,755,098	119,040,065	120,572,028	9,546,812

Arizona Electric Power Cooperative, Inc.

DISTRIBUTION OF RATE BASE BY FUNCTION

LINE NO.	DESCRIPTION	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES	TOTAL AEPCO
1					
2		THIS SCHEDULE IS NOT APPLICABLE			

Arizona Electric Power Cooperative, Inc.

Distribution of Expenses by Resource
(Reclassifications and Pro Forma Adjustments Included

LINE NO.		TOTAL ADJUSTED O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$77,906,029	$77,906,029	$0	$0
4	PRODUCTION - FUEL A/C 547	10,574,530	0	10,574,530	0
5	PRODUCTION - STEAM A/C 500	6,183,360	6,183,360	0	0
6	A/C 502	1,106,502	1,106,502	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	876,286	876,286	0	0
10	A/C 506 & 509	1,094,794	1,094,794	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	242,281	0	242,281	0
14	A/C 548	198,520	0	198,520	0
15	A/C 549	39,576	0	39,576	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY	0	0	0	0
18	- DEMAND A/C 555	3,117,006	751,678	0	2,365,328
19	- ENERGY A/C 555	13,428,376	1,701,090	11,492,376	234,910
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	2,539,437	2,225,793	310,523	3,120
22	A/C 557	0	0	0	0
23	TRANSMISSION		0	0	0
24	A/C 562	819	699	119	0
25	A/C 564	77	65	11	0
26	A/C 565	4,501,921	3,200,940	1,138,980	162,000
27	ADMINISTRATIVE & GENERAL	10,800,350	9,940,732	775,640	83,977
28	TOTAL OPERATIONS	$132,609,861	$104,987,969	$24,772,557	$2,849,334
29					
30	PRODUCTION - STEAM - A/C 510	$1,346,996	$1,346,996	$0	$0
31	A/C 511	27,649	27,649	0	0
32	A/C 512	4,018,147	4,018,147	0	0
33	A/C 513	5,638,224	5,638,224	0	0
34	A/C 514	2,390,050	2,390,050	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	52,802	0	52,802	0
37	A/C 552	3,190,952	0	3,190,952	0
38	A/C 553	1,746,819	0	1,746,819	0
39	A/C 554.	178,828	0	178,828	0
40	TRANSMISSION		0	0	0
41	A/C 570	13,900	11,874	2,026	0
42	GENERAL PLANT	355,096	325,750	25,022	4,325
43	TOTAL MAINTENANCE	$18,959,464	$13,758,690	$5,196,449	$4,325
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$8,317,632	$6,298,879	$1,993,016	$25,737
47	TAXES	2,933,343	2,617,177	316,166	0
48	TOTAL OTHER	$11,250,975	$8,916,056	$2,309,182	$25,737
49					
50	TOTAL OPERATING EXPENSES	$162,820,299	$127,662,715	$32,278,188	$2,879,396
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$10,812,194	$8,149,682	$2,653,298	$9,214
54	INT. CHARGES TO CONST.	(187,816)	(141,566)	(46,090)	(160)
55	OTHER INT. EXPENSE	1,047,090	847,554	193,845	5,690
56	OTHER DEDUCTIONS	151,174	113,947	37,098	129
57	TOTAL INT. & OTHER DED.	$11,822,642	$8,969,617	$2,838,151	$14,873
58					
59	TOTAL EXPENSES	$ 174,642,941	$ 136,632,333	$ 35,116,339	$ 2,894,270
60					
61					
62					
63	SUPPORTING SCHEDULES:				
64	(a) C-1, PAGES 3 AND 4				
65	(b) C-1, PAGE 4, LINES 44 + 50				

Arizona Electric Power Cooperative, Inc.

Distribution of Booked Expenses by Resource

LINE NO.		TOTAL BOOKED O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$61,965,748	$61,965,748	$0	$0
4	PRODUCTION - FUEL A/C 547	10,574,530	0	10,574,530	0
5	PRODUCTION - STEAM A/C 500	5,997,229	5,997,229	0	0
6	A/C 502	2,795,766	2,795,766	0	0
7	A/C 503	0		0	0
8	A/C 504	0		0	0
9	A/C 505	1,385,698	1,385,698	0	0
10	A/C 506 & 509	1,083,857	1,083,857	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	234,983	0	234,983	0
14	A/C 548	707,145	0	707,145	0
15	A/C 549	39,148	0	39,148	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	6,274,506	751,678	2,925,000	2,597,828
19	- ENERGY A/C 555	35,795,431	1,701,090	30,545,119	3,549,222
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	3,315,542	2,906,043	405,426	4,074
22	A/C 557	1,548,021	1,356,826	189,293	1,902
23	TRANSMISSION				
24	A/C 562	819	699	119	0
25	A/C 564	77	65	11	0
26	A/C 565	16,345,082	14,201,775	1,981,307	162,000
27	ADMINISTRATIVE & GENERAL	11,249,966	10,299,504	791,139	159,323
28	TOTAL OPERATIONS	$159,313,546	$104,445,978	$48,393,220	$6,474,348
29					
30	PRODUCTION - STEAM - A/C 510	$1,302,263	$1,302,263	$0	$0
31	A/C 511	26,944	26,944	0	0
32	A/C 512	4,763,936	4,763,936	0	0
33	A/C 513	6,184,656	6,184,656	0	0
34	A/C 514	2,334,541	2,334,541	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	51,049	0	51,049	0
37	A/C 552	27,641	0	27,641	0
38	A/C 553	1,384,550	0	1,384,550	0
39	A/C 554.	175,654	0	175,654	0
40	TRANSMISSION				
41	A/C 570	13,624	11,638	1,986	0
42	GENERAL PLANT	304,878	279,120	21,440	4,318
43	TOTAL MAINTENANCE	$16,569,736	$14,903,098	$1,662,320	$4,318
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$7,883,883	$5,904,356	$1,960,365	$19,162
47	TAXES	0	0	0	0
48	TOTAL OTHER	$7,883,883	$5,904,356	$1,960,365	$19,162
49					
50	TOTAL OPERATING EXPENSES	$183,767,165	$125,253,432	$52,015,905	$6,497,828
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$10,580,757	$7,975,236	$2,596,504	$9,017
54	INT. CHARGES TO CONST.	(187,816)	(141,566)	(46,090)	(160)
55	OTHER INT. EXPENSE	781,804	589,284	191,854	666
56	OTHER DEDUCTIONS	151,174	113,947	37,098	129
57	TOTAL INT. & OTHER DED.	$11,325,919	$8,536,901	$2,779,365	$9,652
58					
59	TOTAL EXPENSES	$ 195,093,084	$ 133,790,334	$ 54,795,271	$ 6,507,480
60					
61					
62					
63	SUPPORTING SCHEDULES:				
64	(a) C-1, PAGES 1 AND 2				
65	(b) C-1, PAGE 2, LINES 44 + 50				

Arizona Electric Power Cooperative, Inc.

Distribution of Pro-Forma Adjustments by Resource

LINE NO.		ADJUSTMENTS TO O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$16,520,095	$16,520,095	$0	$0
4	PRODUCTION - FUEL A/C 547	0	0	0	0
5	PRODUCTION - STEAM A/C 500	354,307	354,307	0	0
6	A/C 502	35,855	35,855	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	0	0	0	0
10	A/C 506 & 509	20,818	20,818	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	13,891	0	13,891	0
14	A/C 548	1,405	0	1,405	0
15	A/C 549	816	0	816	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	(3,157,500)	0	(2,925,000)	(232,500)
19	- ENERGY A/C 555	(22,367,055)	0	(19,052,743)	(3,314,312)
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	109,150	95,669	13,347	134
22	A/C 557	0	0	0	0
23	TRANSMISSION				
24	A/C 562	0	0	0	0
25	A/C 564	0	0	0	0
26	A/C 565	(4,963,137)	(4,963,137)	0	0
27	ADMINISTRATIVE & GENERAL	540,635	477,180	60,665	2,790
28	TOTAL OPERATIONS	($12,890,719)	$12,540,789	($21,887,619)	($3,543,888)
29					
30	PRODUCTION - STEAM - A/C 510	$85,151	$85,151	$0	$0
31	A/C 511	1,342	1,342	0	0
32	A/C 512	(680,227)	(680,227)	0	0
33	A/C 513	(533,229)	(533,229)	0	0
34	A/C 514	105,663	105,663	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	3,337	0	3,337	0
37	A/C 552	3,164,043	0	3,164,043	0
38	A/C 553	376,795	0	376,795	0
39	A/C 554.	6,042	0	6,042	0
40	TRANSMISSION				
41	A/C 570	526	449	77	0
42	GENERAL PLANT	95,593	88,761	6,818	14
43	TOTAL MAINTENANCE	$2,625,037	($932,089)	$3,557,112	$14
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$464,285	$425,060	$32,650	$6,575
47	TAXES	0	0	0	0
48	TOTAL OTHER	$464,285	$425,060	$32,650	$6,575
49					
50	TOTAL OPERATING EXPENSES	($9,801,397)	$12,033,759	($18,297,857)	($3,537,299)
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$231,437	$174,445	$56,794	$197
54	INT. CHARGES TO CONST.	0	0	0	0
55	OTHER INT. EXPENSE	360,470	330,015	25,350	5,105
56	OTHER DEDUCTIONS	0	0	0	0
57	TOTAL INT. & OTHER DED.	$591,907	$504,461	$82,144	$5,302
58					
59	TOTAL EXPENSES	($9,209,490)	$12,538,220	($18,215,713)	($3,531,997)
60					
61					
62					
63	SUPPORTING SCHEDULES:				
64	(a) C-1, PAGES 3 & 4				
65	(b) C-1, PAGE 4, LINES 44 + 50				

Arizona Electric Power Cooperative, Inc.

Distribution of Pro-Forma Adjustments by Resource - Staff Proposed Expense Adjustments

LINE NO.		ADJUSTMENTS TO O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$ (28,439)	$ (28,439)	$ -	$ -
4	PRODUCTION - FUEL A/C 547	-	-	-	-
5	PRODUCTION - STEAM A/C 500	(168,177)	(168,177)	-	-
6	A/C 502	(17,019)	(17,019)	-	-
7	A/C 503	-	-	-	-
8	A/C 504	-	-	-	-
9	A/C 505	(0)	(0)	-	-
10	A/C 506 & 509	(9,882)	(9,882)	-	-
11	A/C 507	-	-	-	-
12	A/C 508	-	-	-	-
13	PRODUCTION - OTHER - A/C 546	(6,594)	-	(6,594)	-
14	A/C 548	(667)	-	(667)	-
15	A/C 549	(387)	-	(387)	-
16	A/C 550	-	-	-	-
17	OTHER POWER SUPPLY		-	-	-
18	- DEMAND A/C 555	-	-	-	-
19	- ENERGY A/C 555	-	-	-	-
20	- INDIRECT A/C 555	-	-	-	-
21	A/C 556	(51,810)	(45,411)	(6,335)	(64)
22	A/C 557	-	-	-	-
23	TRANSMISSION		-	-	-
24	A/C 562	-	-	-	-
25	A/C 564	-	-	-	-
26	A/C 565	-	-	-	-
27	ADMINISTRATIVE & GENERAL	(1,254,542)	(1,077,913)	(94,750)	(81,879)
28	TOTAL OPERATIONS	$ (1,537,517)	$ (1,346,841)	$ (108,733)	$ (81,943)
29					
30	PRODUCTION - STEAM - A/C 510	$ (40,418)	$ (40,418)	$ -	$ -
31	A/C 511	(637)	(637)	-	-
32	A/C 512	(65,562)	(65,562)	-	-
33	A/C 513	(13,203)	(13,203)	-	-
34	A/C 514	(50,155)	(50,155)	-	-
35	A/C 515.	-	-	-	-
36	PRODUCTION - OTHER - A/C 551	(1,584)	-	(1,584)	-
37	A/C 552	(732)	-	(732)	-
38	A/C 553	(14,526)	-	(14,526)	-
39	A/C 554.	(2,868)	-	(2,868)	-
40	TRANSMISSION		-	-	-
41	A/C 570	(250)	(213)	(36)	-
42	GENERAL PLANT	(45,374)	(42,132)	(3,236)	(6)
43	TOTAL MAINTENANCE	$ (235,309)	$ (212,319)	$ (22,983)	$ (6)
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$ (30,536)	$ (30,536)		
47	TAXES	-			
48	TOTAL OTHER	$ (30,536)	$ (30,536)	$ -	$ -
49					
50	TOTAL OPERATING EXPENSES	$ (1,803,362)	$ (1,589,697)	$ (131,716)	$ (81,949)
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$ -			
54	INT. CHARGES TO CONST.	-			
55	OTHER INT. EXPENSE	(95,184)	(71,745)	(23,358)	(81)
56	OTHER DEDUCTIONS	-			
57	TOTAL INT. & OTHER DED.	$ (95,184)	$ (71,745)	$ (23,358)	$ (81)
58					
59	TOTAL EXPENSES	$ (1,898,546)	$ (1,661,442)	$ (155,074)	$ (82,030)
60					
61					
62					
63	SUPPORTING SCHEDULES:				
64	(a) GLG Sch. G-6, PAGES 3.2 & 3.3				
65					

Arizona Electric Power Cooperative, Inc.

Distribution of Staff Payroll and Benefit Adjustment to O&M Expense Accounts

			Distribution of Booked Payroll by Resource			Distribution of Payroll Adjustment by Resource				AEPCO Distribution of Adjusted Payroll by Resource				Dist. of Staff Payroll/Benefits/Incentive C-1 Adj. by Resource			
Line	Account Description	Total Book Labor	Base	Other Existing Resources	Additional ARM Resources	Payroll Adjustment	Base	Other Existing Resources	Additional ARM Resources	Adjusted Payroll	Base	Other Existing Resources	Additional ARM Resources	Adjustments Payroll	Base	Other Existing Resources	Additional ARM Resources
1	OPERATING EXPENSES:																
2	OPERATIONS																
3	PRODUCTION - FUEL A/C 501	$709,893	$709,893	$0	$0	$59,915	$59,915	$0	$0	$769,808	$769,808	$0	$0	($28,439)	($28,439)	$0	$0
4	PRODUCTION - FUEL A/C 547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	PRODUCTION - STEAM A/C 500	4,197,952	4,197,952	0	0	354,307	354,307	0	0	4,552,260	4,552,260	0	0	(168,177)	(168,177)	0	0
6	A/C 502	424,827	424,827	0	0	35,855	35,855	0	0	460,682	460,682	0	0	(17,019)	(17,019)	0	0
7	A/C 503	0				0								0	0	0	0
8	A/C 504	0				0								0	0	0	0
9	A/C 505	0	0	0	0	0	0	0	0	0	0	0	0	(0)	(0)	0	0
10	A/C 506 & 509	246,663	246,663	0	0	20,818	20,818	0	0	267,481	267,481	0	0	(9,882)	(9,882)	0	0
11	A/C 507	0				0								0	0	0	0
12	A/C 508	0				0								0	0	0	0
13	PRODUCTION - OTHER - A/C 546	164,589	0	164,589	0	13,891	0	13,891	0	178,481	0	178,481	0	(6,594)	0	(6,594)	
14	A/C 548	16,643	0	16,643	0	1,405	0	1,405	0	18,048	0	18,048	0	(667)	0	(667)	
15	A/C 549	9,663	0	9,663	0	816	0	816	0	10,479	0	10,479	0	(387)	0	(387)	
16	A/C 550	0				0								0	0	0	0
17	OTHER POWER SUPPLY					0								0	0	0	0
18	- DEMAND A/C 555	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	- ENERGY A/C 555	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	- INDIRECT A/C 555	0				0				0	0	0	0	0	0	0	0
21	A/C 556	1,293,251	1,133,523	158,139	1,589	109,150	95,669	13,347	134	1,402,401	1,229,192	171,486	1,723	(51,810)	(45,411)	(6,335)	(64)
22	A/C 557	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TRANSMISSION					0				0	0	0	0	0	0	0	0
24	A/C 562	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	A/C 564	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	A/C 565	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	ADMINISTRATIVE & GENERAL	9,918,220	9,209,404	707,405	1,411	380,635	353,433	27,148	54	10,298,856	9,562,837	734,554	1,465	(380,476)	(353,285)	(27,137)	(54)
28	TOTAL OPERATIONS	$16,981,703	$15,922,262	$1,056,441	$3,000	$976,793	$919,998	$56,607	$188	$17,958,496	$16,842,260	$1,113,048	$3,188	($663,451)	($622,213)	($41,120)	($118)
29														0	0	0	0
30	PRODUCTION - STEAM - A/C 510	1,008,899	$1,008,899	$0	$0	85,151	$85,151	$0	$0	1,094,051	1,094,051	0	0	(40,418)	(40,418)	0	0
31	A/C 511	15,895	15,895	0	0	1,342	1,342	0	0	17,237	17,237	0	0	(637)	(637)	0	0
32	A/C 512	1,636,533	1,636,533	0	0	138,123	138,123	0	0	1,774,656	1,774,656	0	0	(65,562)	(65,562)	0	0
33	A/C 513	329,560	329,560	0	0	27,815	27,815	0	0	357,375	357,375	0	0	(13,203)	(13,203)	0	0
34	A/C 514	1,251,936	1,251,936	0	0	105,663	105,663	0	0	1,357,599	1,357,599	0	0	(50,155)	(50,155)	0	0
35	A/C 515.	0												0	0	0	0
36	PRODUCTION - OTHER - A/C 551	39,541	0	39,541	0	3,337	0	3,337	0	42,879	0	42,879	0	(1,584)	0	(1,584)	0
37	A/C 552	18,280	0	18,280	0	1,543	0	1,543	0	19,823	0	19,823	0	(732)	0	(732)	0
38	A/C 553	362,598	0	362,598	0	30,603	0	30,603	0	393,202	0	393,202	0	(14,526)	0	(14,526)	0
39	A/C 554.	71,588	0	71,588	0	6,042	0	6,042	0	77,630	0	77,630	0	(2,868)	0	(2,868)	0
40	TRANSMISSION													0	0	0	0
41	A/C 570	6,232	5,323	908	0	526	449	77	0	6,757	5,772	985	0	(250)	(213)	(36)	0
42	GENERAL PLANT	1,132,617	1,051,673	80,783	161	95,593	88,761	6,818	14	1,228,209	1,140,434	87,601	175	(45,374)	(42,132)	(3,236)	
43	TOTAL MAINTENANCE	$5,873,679	$5,299,819	$573,699	$161	$495,739	$447,305	$48,420	$14	$6,369,418	$5,747,125	$622,119	$175	($235,309)	($212,319)	($22,983)	
44																	
45	TOTAL LABOR	$22,855,382	$21,222,082	$1,630,139	$3,161	$1,472,532	$1,367,303	$105,027	$202	$24,327,914	$22,589,385	$1,735,167	$3,362	($898,760)	($834,533)	($64,103)	($124)
46																	
47	PAYROLL ALLOCATOR 1	100.000%	92.8538%	7.1324%	0.0138%					100.000%	92.853%	7.132%	0.014%	($898,760) Staff C-1 Adj. Net Decrease In Labor Expenses			
48	PAYROLL ALLOCATOR 2	100.000%	92.8666%	7.1334%						5.049%	4.688%	0.360%		Allocated based upon ratio of As-filed account $/Total Labor$			

Arizona Electric Power Cooperative, Inc.

Distribution of Pro-Forma Adjustments by Resource - Staff Adjustments

Staff Adj.	Description	Staff Alloc. Factor Ref.	Dist. of Staff Adjustments by Resource: Staff Adjustments	Base	Other Existing Resources	Additional ARM Resources
C-1	Var. Accts. Payroll Related Adjustments	See G-6,p3.2, L45	$ (898,760)	$ (834,533)	$ (64,103)	$ (124)
C-2	A&G - Removal of Incentive Compensation	A-2	$ (681,900)	$ (565,316)	$ (52,748)	$ (63,836)
C-3	A&G - Removal of Donations Expenses	A-2	$ (79,926)	$ (66,261)	$ (6,183)	$ (7,482)
C-4	A&G - Removal of Lobbying Expenses	A-2	$ (112,240)	$ (93,051)	$ (8,682)	$ (10,507)
C-5a	Depr. - ST2 & ST3 Reduction In Depr. Exp.	A-3	$ (30,536)	$ (30,536)	$ -	$ -
C-5b	Other. Int. Exp - Reductrion In Accretion Exp.	A-4	$ (95,184)	$ (71,745)	$ (23,358)	$ (81)
	Total Staff Expense Adjustments		$ (1,898,546)	$ (1,661,442)	$ (155,074)	$ (82,030)
	Development of Staff Allocation Factors					
	Total Admin & General	AEPCO G-6,p1,L27	$ 12,054,892	$ 11,018,645	$ 870,391	$ 165,856
	Payroll Expenses	See G-6,p3.2,L27	10,298,856	9,562,837	734,554	1,465
	A&G Net Of Payroll		$ 1,756,036	$ 1,455,808	$ 135,837	$ 164,391
	Staff Allocation Factor	A-2	100%	82.90%	7.74%	9.36%
	ST2 & ST3 Depr. Direct Staff Alloc. Factor	A-3	100%	100.00%	0.00%	0.00%
	Int. On Long Term Debt -AEPCO G-6,p2 L53	AEPCO G-6,p2,L53	$10,580,757	$7,975,236	$2,596,504	$9,017
	Staff Allocation Factor	A-4	100%	75.37%	24.54%	0.09%

Arizona Electric Power Cooperative, Inc.

Distribution of Expense Reclassifications by Resource

LINE NO.		RECLASSIFICATIONS OF O&M EXPENSES	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	($551,375)	(551,375)	$0	$0
4	PRODUCTION - FUEL A/C 547	0	0	0	0
5	PRODUCTION - STEAM A/C 500	0	0	0	0
6	A/C 502	(1,708,100)	(1,708,100)	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	(509,412)	(509,412)	0	0
10	A/C 506 & 509	0	0	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	0	0	0	0
14	A/C 548	(509,363)	0	(509,363)	0
15	A/C 549	0	0	0	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	0	0		
19	- ENERGY A/C 555	0	0	0	0
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	(833,446)	(730,508)	(101,914)	(1,024)
22	A/C 557	(1,548,021)	(1,356,826)	(189,293)	(1,902)
23	TRANSMISSION				
24	A/C 562	0	0	0	0
25	A/C 564	0	0	0	0
26	A/C 565	(6,880,024)	(6,037,697)	(842,327)	0
27	ADMINISTRATIVE & GENERAL	264,291	241,962	18,586	3,743
28	TOTAL OPERATIONS	($12,275,450)	($10,651,957)	($1,624,310)	$817
29					
30	PRODUCTION - STEAM - A/C 510	$0	$0	$0	$0
31	A/C 511	0	0	0	0
32	A/C 512	0	0	0	0
33	A/C 513	0	0	0	0
34	A/C 514	0	0	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	0	0	0	0
37	A/C 552	0	0	0	0
38	A/C 553	0	0	0	0
39	A/C 554.	0	0	0	0
40	TRANSMISSION				
41	A/C 570	0	0	0	0
42	GENERAL PLANT	0	0	0	0
43	TOTAL MAINTENANCE	$0	$0	$0	$0
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$0	$0	$0	$0
47	TAXES	2,933,343	2,617,177	316,166	0
48	TOTAL OTHER	$2,933,343	$2,617,177	$316,166	$0
49					
50	TOTAL OPERATING EXPENSES	($9,342,107)	($8,034,780)	($1,308,144)	$817
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$0	$0	$0	$0
54	INT. CHARGES TO CONST.	0	0	0	0
55	OTHER INT. EXPENSE	0	0	0	0
56	OTHER DEDUCTIONS	0	0	0	0
57	TOTAL INT. & OTHER DED.	$0	$0	$0	$0
58					
59	TOTAL EXPENSES	($9,342,107)	($8,034,780)	($1,308,144)	$817
60					
61					
62					
63	SUPPORTING SCHEDULES:				
64	(a) C-2, PAGES 1 & 2				
65	(b) C-2, PAGE 2, LINES 44 + 50				

Arizona Electric Power Cooperative, Inc.

Class A Member Revenue Requirements by Function

LINE NO.		BASE RESOURCES			OTHER EXISTING RESOURCES			ADDITIONAL ARM RESOURCES			TOTAL AEPCO REVENUE REQUIREMENT			
		FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	Total
1	OPERATING EXPENSES:													
2	OPERATIONS													
3	PRODUCTION - FUEL A/C 501	$19,375	$0	$77,886,654	$0	$0	$0	$0	$0	$0	$19,375	$0	$77,886,654	$77,906,029
4	PRODUCTION - FUEL A/C 547	0	0	0	109,790	0	10,464,740	0	0	0	109,790	0	10,464,740	10,574,530
5	PRODUCTION - STEAM A/C 500	0	6,183,360	0	0	0	0	0	0	0	0	6,183,360	0	6,183,360
6	A/C 502	1,123,521	(17,019)	0	0	0	0	0	0	0	1,123,521	(17,019)	0	1,106,502
7	A/C 503	0	0	0	0	0	0	0	0	0	0	0	0	0
8	A/C 504	0	0	0	0	0	0	0	0	0	0	0	0	0
9	A/C 505	92,400	783,886	0	0	0	0	0	0	0	92,400	783,886	0	876,286
10	A/C 506 & 509	0	1,094,794	0	0	0	0	0	0	0	0	1,094,794	0	1,094,794
11	A/C 507	0	0	0	0	0	0	0	0	0	0	0	0	0
12	A/C 508	0	0	0	0	0	0	0	0	0	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	0	0	0	0	242,281	0	0	0	0	0	242,281	0	242,281
14	A/C 548	0	0	0	79,166	119,354	0	0	0	0	79,166	119,354	0	198,520
15	A/C 549	0	0	0	0	39,576	0	0	0	0	0	39,576	0	39,576
16	A/C 550	0	0	0	0	0	0	0	0	0	0	0	0	0
17	OTHER POWER SUPPLY													
18	- DEMAND A/C 555	751,678	0	0	0	0	0	2,365,328	0	0	3,117,006	0	0	3,117,00
19	- ENERGY A/C 555	0		1,701,090	0	0	11,492,376	0	0	234,910	0	0	13,428,376	13,428,376
20	- INDIRECT A/C 555	0	0	0	0	0	0	0	0	0	0	0	0	0
21	A/C 556	0	2,225,793	0	0	310,523	0	0	3,120	0	0	2,539,437	0	2,539,437
22	A/C 557	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TRANSMISSION													
24	A/C 562	0	699	0	0	119	0	0	0	0	0	819	0	819
25	A/C 564	0	65	0	0	11	0	0	0	0	0	77	0	77
26	A/C 565	0	3,198,060	2,880	0	1,138,980	0	0	162,000	0	0	4,499,040	2,880	4,501,921
27	ADMINISTRATIVE & GENERAL	0	9,940,732	0		775,640	0	0	83,977	0	0	10,800,350	0	10,800,350
28	TOTAL OPERATIONS	$1,986,974	$23,410,371	$79,590,624	$188,956	$2,626,485	$21,957,116	$2,365,328	$249,097	$234,910	$4,541,257	$26,285,953	$101,782,650	$132,609,861
29														
30	PRODUCTION - STEAM - A/C 510	0	1,346,996	0	0	0	0	0	0	0	0	1,346,996	0	1,346,996
31	A/C 511	0	27,649	0	0	0	0	0	0	0	0	27,649	0	27,649
32	A/C 512	0	4,018,147	0	0	0	0	0	0	0	0	4,018,147	0	4,018,147
33	A/C 513	0	5,638,224	0	0	0	0	0	0	0	0	5,638,224	0	5,638,224
34	A/C 514	0	2,390,050	0	0	0	0	0	0	0	0	2,390,050	0	2,390,050
35	A/C 515.	0	0	0	0	0	0	0	0	0	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	0	0	0	0	52,802	0	0	0	0	0	52,802	0	52,802
37	A/C 552	0	0	0	0	3,190,952	0	0	0	0	0	3,190,952	0	3,190,952
38	A/C 553	0	0	0	0	1,746,819	0	0	0	0	0	1,746,819	0	1,746,819
39	A/C 554.	0	0	0	0	178,828	0	0	0	0	0	178,828	0	178,828
40	TRANSMISSION													
41	A/C 570	0	11,874	0	0	2,026	0	0	0	0	0	13,900	0	13,900
42	GENERAL PLANT	0	325,750	0	0	25,022	0	0	4,325	0	0	355,096	0	355,096
43	TOTAL MAINTENANCE	$0	$13,758,690	$0	$0	$5,196,449	$0	$0	$4,325	$0	$0	$18,959,464	$0	$18,959,464
44														
45	OTHER:													
46	DEPRECIATION & AMORTIZATION	$6,298,879	$0	$0	$1,993,016	$0	$0	$25,737	$0	$0	8,317,632	0	0	8,317,632
47	TAXES	2,617,177	0	0	316,166	0	0	0	0	0	2,933,343	0	0	2,933,343
48	TOTAL OTHER	$8,916,056	$0	$0	$2,309,182	$0	$0	$25,737	$0	$0	$11,250,975	$0	$0	$11,250,97
49														
50	TOTAL OPERATING EXPENSES	$10,903,030	$37,169,061	$79,590,624	$2,498,138	$7,822,934	$21,957,116	$2,391,065	$253,422	$234,910	$15,792,232	$45,245,417	$101,782,650	$162,820,299
51														
52	INT. & OTHER DEDUCTIONS:													
53	INT. ON LONG-TERM DEBT	$8,149,682	$0	$0	$2,653,298	$0	$0	$9,214	$0	$0	$10,812,194	$0	$0	$10,812,194
54	INT. CHARGES TO CONST.	(141,566)	0	0	(46,090)	0	0	(160)	0	0	(187,816)	0	0	(187,816)
55	OTHER INT. EXPENSE	847,554	0	0	193,845	0	0	5,690	0	0	1,047,090	0	0	1,047,090
56	OTHER DEDUCTIONS	113,947	0	0	37,098	0	0	129	0	0	151,174	0	0	151,174
57	TOTAL INT. & OTHER DED.	$8,969,617	$0	$0	$2,838,151	$0	$0	$14,873	$0	$0	$11,822,642	$0	$0	$11,822,642
58														
59	TOTAL EXPENSES	$19,872,647	$37,169,061	$79,590,624	$5,336,289	$7,822,934	$21,957,116	$2,405,938	$253,422	$234,910	$27,614,874	$45,245,417	$101,782,650	$174,642,941
60														
61	REVENUE CREDITS													
62	FIRM CONTRACT REVENUES	$1,430,539	$0	$2,448,992	$0	$0	$0	$0	$0	$0	$1,430,539	$0	$2,448,992	$3,879,531
63	ECONOMY ENERGY	0	0	3,504,243	0	0	448,029	0	0	0	0	0	3,952,272	3,952,272
64	SCHEDULING REVENUES	788,294	0	0	0	0	0	0	0	0	788,294	0	0	788,294
65	OTHER OPERATING REVENUES	997,566	1,865,811	0	267,871	392,695	0	0	0	0	1,265,437	2,258,506	0	3,523,943
66	TOTAL REVENUE CREDITS	$3,216,399	$1,865,811	$5,953,235	$267,871	$392,695	$448,029	$0	$0	$0	$3,484,270	$2,258,506	$6,401,264	$12,144,040
67														
68	MARGINS	2,034,469	0	0	619,079	0	0	293,872	0	0	2,947,420	0	0	2,947,420
69														
70	CLASS A MEMBER REVENUE REQUIREMENTS	$ 18,690,717	$ 35,303,250	$ 73,637,389	$ 5,687,497	$ 7,430,239	$ 21,509,087	$ 2,699,810	$253,422	$ 234,910	$ 27,078,024	$ 42,986,911	$ 95,381,386	$ 165,446,321

Arizona Electric Power Cooperative, Inc.

DERIVATION OF ALLOCATION FACTORS

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO	TRICO PRM	CARMs
1	ALLOCATION FACTORS						
2	ENERGY ALLOCATION FACTORS						
3	BASE RESOURCE KWH	784,700,545	738,282,902	759,805,654	2,282,789,101	522,616,908	226,109,971
4	OTHER EXISTING RESOURCES KWH	90,679,515	108,755,098	119,040,065	318,474,678	120,572,028	9,546,812
5	ADDITIONAL ARM RESOURCES KWH	0	0	3,200,000	3,200,000	3,097,600	102,400
6							
7	BASE RESOURCE KWH	34.375%	32.341%	33.284%	100.000%	22.894%	9.905%
8	OTHER EXISTING RESOURCES KWH	28.473%	34.149%	37.378%	100.000%	37.859%	2.998%
9	ADDITIONAL ARM RESOURCES KWH	0.000%	0.000%	100.000%	100.000%	96.800%	3.200%
10							
11	FIXED COST ALLOCATION FACTORS						
12	ACP	35.800%	31.700%	32.500%	100.000%	21.100%	11.400%
13	ACP OF SOUTH POINT & GRIFFITH	0.000%	0.000%	100.000%	100.000%	96.800%	3.200%
14							

15	FUNCTIONALIZATION FACTORS	BASE RESOURCES	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES	TOTAL AEPCO
16	DISPATCHED ENERGY (KWH)	2,282,789,101	318,474,678	3,200,000	2,604,463,779
17	DISPATCHED ENERGY (%)	87.649%	12.228%	0.123%	100.000%
18					
19	SUB-TOTAL PURCHASED POWER				
20	PRODUCTION - FUEL A/C 501	$61,965,748	$0	$0	$61,965,748
21	PRODUCTION - FUEL A/C 547	0	10,574,530	0	10574530
22	SUBTOTAL ($)	$61,965,748	$10,574,530	$0	$72,540,278
23	SUBTOTAL (%)	85.423%	14.577%	0.000%	100.000%
24					
25	PAYROLL EXCLUDING A&G AND GEN PLT MNTC ($)	$10,961,004	$841,952	$1,589	$11,804,545
26	PAYROLL EXCLUDING A&G AND GEN PLT MNTC (%)	92.854%	7.132%	0.013%	100.000%
27					
28	INTEREST ON LONG TERM DEBT ($)	$7,975,236	$2,596,504	$9,017	$10,580,757
29	INTEREST ON LONG TERM DEBT (%)	75.375%	24.540%	0.085%	100.000%
30					
31	TOTAL EXPENSES LESS A&G ($)	$126,691,600	$34,340,699	$2,810,293	$163,842,592
32	TOTAL EXPENSES LESS A&G (%)	77.325%	20.960%	1.715%	100.000%
33					
34	A&G EXPENSES ($)	$10,299,504	$791,139	$159,323	$11,249,966
35	A&G EXPENSES (%)	91.551%	7.032%	1.416%	100.000%

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class
March 31, 2009 Adjusted Test Year

Line No.	CLASS OF SERVICE	PRESENT	PROPOSED	AMOUNT	PERCENT
1	Total Class A Member Revenues	$166,618,638	$165,446,321	($1,172,317)	-0.70%
2	Non-Members	8,620,097	8,620,097	0	0.00%
3	Other Operating Revenues	3,523,943	3,523,943	0	0.00%
4	Total AEPCO	$178,762,678	$177,590,361	($1,172,317)	-0.66%

Note: Revenues stated using synchronized FPPCA.

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class
March 31, 2009 Adjusted Test Year

Line No.	CLASS OF SERVICE	CUSTOMERS	KWH CONSUMPTION	BILLING KW	REVENUE PRESENT	REVENUE PROPOSED	PROPOSED INCREASE ($)	PROPOSED INCREASE (%)
1	Member Contracts:							
2	Anza	1	51,283,408	96,412	$3,353,127	$3,260,032	($93,095)	-2.78%
3	Duncan	1	28,079,760	57,180	1,901,744	1,858,063	(43,680)	-2.30%
4	Graham	1	156,396,015	324,562	10,683,325	10,446,493	(236,832)	-2.22%
5	Mohave	1	875,380,060	1,723,399	54,205,506	55,489,632	1,284,127	2.37%
6	Sulphur	1	847,038,000	1,629,806	52,026,365	52,370,038	343,673	0.66%
7	Trico	1	646,286,536	1,361,311	44,448,572	42,022,063	(2,426,509)	-5.46%
8	Total Class A Members	6	2,604,463,779	5,192,670	$166,618,638	$165,446,321	($1,172,317)	-0.70%
9								
10	Other Firm Contracts:							
11	City of Mesa	0	0	0	$0	$0	N/A	N/A
12	Salt River Project	0	0	0	0	0	N/A	N/A
13	Public Service Company of New Mexico	0	0	0	0	0	N/A	N/A
14	ED2	1	68,952,281	96,000	3,879,531	3,879,531	$0	0.00%
15	Total Firm Contracts	1	68,952,281	96,000	$3,879,531	$3,879,531	$0	0.00%
16								
17	Total AEPCO	7	2,673,416,060	5,288,670	$170,498,169	$169,325,852	($1,172,317)	-0.69%

Note: Revenues stated using synchronized FPPCA.

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER BOOKED SALES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1														
2	ANZA													
3	MW	5.712	7.488	10.608	10.404	9.948	9.684	6.852	5.388	8.860	8.093	7.071	6.304	96.412
4	MWH	3,733.956	3,974.280	4,547.868	5,266.380	5,087.034	4,309.788	3,861.588	3,682.884	4,682.804	4,126.590	3,963.021	4,047.215	51,283.408
5														
6	DUNCAN													
7	MW	3.860	6.040	6.960	5.940	6.620	5.360	4.020	2.780	4.300	3.900	3.900	3.500	57.180
8	MWH	2,004.660	2,422.840	3,223.350	2,960.420	2,955.880	2,300.600	1,919.560	1,905.850	2,292.120	2,226.640	1,883.390	1,984.450	28,079.760
9														
10	GRAHAM													
11	MW	20.966	31.511	39.951	39.726	36.986	32.263	24.988	18.448	20.642	19.992	18.818	20.271	324.562
12	MWH	10,775.112	12,244.130	18,499.166	17,976.098	17,655.323	13,801.595	11,076.763	10,334.556	12,000.020	11,134.378	9,221.331	11,677.543	156,396.015
13														
14	MOHAVE													
15	MW	95.000	103.000	110.000	132.000	133.000	124.000	102.000	72.000	79.000	79.000	75.000	54.000	1,158.000
16	MWH	62,986.000	66,854.000	69,860.000	77,273.000	77,009.000	68,313.000	58,371.000	45,187.000	48,485.000	46,549.000	40,805.000	39,120.000	700,812.000
17														
18	SULPHUR													
19	MW	84.000	88.000	102.000	96.000	97.000	100.000	89.000	77.000	97.000	97.000	104.000	91.000	1,122.000
20	MWH	56,633.000	61,631.000	61,830.000	61,828.000	62,148.000	59,310.000	55,640.000	48,978.000	56,895.000	57,703.000	53,357.000	56,528.000	692,481.000
21														
22	TRICO													
23	MW	85.694	125.853	164.497	149.759	155.557	140.957	116.234	91.507	90.195	85.104	80.967	72.836	1,359.160
24	MWH	43,348.839	49,883.272	69,143.826	72,230.849	72,594.073	62,002.723	50,728.275	42,934.549	49,950.664	48,018.911	41,759.997	43,690.558	646,286.536
25														
26														
27														
28	FULL REQUIREMENTS													
29	MW	30.538	45.039	57.519	56.070	53.554	47.307	35.860	26.616	33.802	31.985	29.789	30.075	478.154
30	MWH	16,513.728	18,641.250	26,270.384	26,202.898	25,698.237	20,411.983	16,857.911	15,923.290	18,974.944	17,487.608	15,067.742	17,709.208	235,759.183
31														
32	PARTIAL REQUIREMENTS													
33	MW	264.694	316.853	376.497	377.759	385.557	364.957	307.234	240.507	266.195	261.104	259.967	217.836	3,639.160
34	MWH	162,967.839	178,368.272	200,833.826	211,331.849	211,751.073	189,625.723	164,739.275	137,099.549	155,330.664	152,270.911	135,921.997	139,338.558	2,039,579.536
35														
36														
37														
38	TOTAL CLASS A													
39	MW	295.232	361.892	434.016	433.829	439.111	412.264	343.094	267.123	299.997	293.089	289.756	247.911	4,117.314
40	MWH	179,481.567	197,009.522	227,104.210	237,534.747	237,449.310	210,037.706	181,597.186	153,022.839	174,305.608	169,758.519	150,989.739	157,047.766	2,275,338.719

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED SALES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	ANZA													
2	MW	5.712	7.488	10.608	10.404	9.948	9.684	6.852	5.388	8.860	8.093	7.071	6.304	96.412
3	MWH	3,733.956	3,974.280	4,547.868	5,266.380	5,087.034	4,309.788	3,861.588	3,682.884	4,682.804	4,126.590	3,963.021	4,047.215	51,283.408
4														
5	DUNCAN													
6	MW	3.860	6.040	6.960	5.940	6.620	5.360	4.020	2.780	4.300	3.900	3.900	3.500	57.180
7	MWH	2,004.660	2,422.840	3,223.350	2,960.420	2,955.880	2,300.600	1,919.560	1,905.850	2,292.120	2,226.640	1,883.390	1,984.450	28,079.760
8														
9	GRAHAM													
10	MW	20.966	31.511	39.951	39.726	36.986	32.263	24.988	18.448	20.642	19.992	18.818	20.271	324.562
11	MWH	10,775.112	12,244.130	18,499.166	17,976.098	17,655.323	13,801.595	11,076.763	10,334.556	12,000.020	11,134.378	9,221.331	11,677.543	156,396.015
12														
13	MOHAVE													
14	MW	131.516	139.516	146.516	168.516	169.516	160.516	138.516	108.516	115.516	114.800	110.800	89.800	1,594.044
15	CHEMSTAR O&M ADJ	0.000	0.000	0.000	0.000	0.000	(2.270)	0.000	0.000	0.000	(2.270)	0.000	(2.270)	(6.810)
16	POWER FACTOR ADJ	0.672	0.793	1.155	0.938	0.886	0.458	0.223	0.133	0.000	0.000	0.033	0.144	5.435
17	SCHED B O&M ADJ	0.000	23.765	33.100	11.400	10.300	19.000	8.800	0.300	3.600	3.065	5.400	12.000	130.730
18	ADJ MW	132.188	164.074	180.771	180.854	180.702	177.704	147.539	108.949	119.116	115.595	116.233	99.674	1,723.399
19	ENERGY MIN ADJ	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	12.000	4.000	39.000	4.000	59.000
20	ADJUSTED MWH	77,807.200	82,169.240	84,665.830	92,587.670	92,324.240	83,134.200	73,686.240	60,008.200	63,812.240	59,870.600	52,872.800	52,441.600	875,380.060
21														
22	SULPHUR													
23	MW	116.334	120.334	134.334	128.334	129.334	132.334	121.334	109.334	129.334	128.700	135.700	122.700	1,508.106
24	POWER FACTOR ADJ	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	SCHED B O&M ADJ	14.800	17.600	12.700	11.400	8.400	3.600	10.800	9.000	12.200	12.000	3.000	6.200	121.700
26	ADJ MW	131.134	137.934	147.034	139.734	137.734	135.934	132.134	118.334	141.534	140.700	138.700	128.900	1,629.806
27	ENERGY MIN ADJ	0.000	0.000	3.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3.000
28	ADJUSTED MWH	69,758.600	75,194.120	74,958.600	75,391.120	75,711.120	72,435.600	69,203.120	62,103.600	70,458.120	69,495.400	64,008.200	68,320.400	847,038.000
29														
30	TRICO													
31	MW	85.694	125.853	164.497	149.759	155.557	140.957	116.234	91.507	90.195	85.104	80.967	72.836	1,359.160
32	MWH	43,348.839	49,883.272	69,143.826	72,230.849	72,594.073	62,002.723	50,728.275	42,934.549	49,950.664	48,018.911	41,759.997	43,690.558	646,286.536
33														
34														
35														
36	FULL REQUIREMENTS													
37	MW	30.538	45.039	57.519	56.070	53.554	47.307	35.860	26.616	33.802	31.985	29.789	30.075	478.154
38	MWH	16,513.728	18,641.250	26,270.384	26,202.898	25,698.237	20,411.983	16,857.911	15,923.290	18,974.944	17,487.608	15,067.742	17,709.208	235,759.183
39														
40	PARTIAL REQUIREMENTS													
41	MW	349.016	427.861	492.302	470.347	473.993	454.595	395.907	318.790	350.845	341.399	335.900	301.410	4,712.365
42	MWH	190,914.639	207,246.632	228,768.256	240,209.639	240,629.433	217,572.523	193,617.635	165,046.349	184,221.024	177,384.911	158,640.997	164,452.558	2,368,704.596
43														
44														
45														
46	TOTAL CLASS A													
47	MW	379.554	472.900	549.821	526.417	527.547	501.902	431.767	345.406	384.647	373.384	365.689	331.485	5,190.519
48	MWH	207,428.367	225,887.882	255,038.640	266,412.537	266,327.670	237,984.506	210,475.546	180,969.639	203,195.968	194,872.519	173,708.739	182,161.766	2,604,463.779

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED BILLING DETERMINANTS

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	ANZA													
2	KW	5,712	7,488	10,608	10,404	9,948	9,684	6,852	5,388	8,860	8,093	7,071	6,304	96,412
3	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
4	KWH - BASE RESOURCES	3,516,089	3,974,280	4,058,041	5,070,048	4,966,884	4,304,383	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	3,076,659	49,283,270
5	KWH - OTHER EXISTING RESOURCES	217,867	0	489,827	196,332	104,947	0	0	0	0	0	0	970,556	1,979,530
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	15,203	5,405	0	0	0	0	0	0	20,608
7														
8	DUNCAN													
9	KW	3,860	6,040	6,960	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
10	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
11	KWH - BASE RESOURCES	1,887,693	2,422,840	2,876,180	2,850,055	2,886,066	2,297,715	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,508,562	26,956,670
12	KWH - OTHER EXISTING RESOURCES	116,967	0	347,170	110,365	60,981	0	0	0	0	0	0	475,888	1,111,371
13	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	8,834	2,885	0	0	0	0	0	0	11,719
14														
15	GRAHAM													
16	KW	20,966	31,511	39,951	39,726	36,986	32,263	24,988	18,448	20,642	19,992	18,818	20,271	324,562
17	KWH - TOTAL	10,775,112	12,244,130	18,499,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
18	KWH - BASE RESOURCES	10,146,411	12,244,130	16,506,717	17,305,943	17,238,326	13,784,286	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	8,877,170	149,870,030
19	KWH - OTHER EXISTING RESOURCES	628,701	0	1,992,449	670,155	364,234	(0)	0	0	0	0	0	2,800,373	6,455,912
20	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	52,763	17,309	0	0	0	0	0	0	70,073
21														
22	MOHAVE													
23	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
24	KWH - TOTAL	77,807,200	82,169,240	84,665,830	92,587,670	92,324,240	83,134,200	73,686,240	60,008,200	63,812,240	59,870,600	52,872,800	52,441,600	875,380,060
25	KWH - BASE RESOURCES	50,755,139	78,652,286	76,386,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
26	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,679,515
27	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
28														
29	SULPHUR													
30	KW	131,134	137,934	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	138,700	128,900	1,629,806
31	KWH - TOTAL	69,758,600	75,194,120	74,958,600	75,391,120	75,711,120	72,435,600	69,203,120	62,103,600	70,458,120	69,495,400	64,008,200	68,320,400	847,038,000
32	KWH - BASE RESOURCES	45,109,060	71,215,789	67,765,404	69,476,928	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	38,296,091	738,282,902
33	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
34	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
35														
36	TRICO													
37	KW	85,906	125,972	164,592	149,858	155,646	141,128	116,545	91,700	90,417	85,278	81,248	73,021	1,361,311
38	KWH - TOTAL	43,348,839	49,883,272	69,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
39	KWH - BASE RESOURCES	30,122,267	46,767,098	49,428,600	52,271,075	52,631,923	49,492,013	44,675,503	41,333,563	47,031,999	44,237,586	39,114,179	25,511,101	522,616,908
40	KWH - OTHER EXISTING RESOURCES	13,226,572	3,116,174	19,715,226	19,959,774	17,638,950	11,736,310	6,052,772	1,600,986	2,918,665	3,781,325	2,645,818	18,179,457	120,572,028
41	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,323,200	774,400	0	0	0	0	0	0	3,097,600
42														
43														
44														
45	FULL REQUIREMENTS													
46	KW	30,538	45,039	57,519	56,070	53,554	47,307	35,860	26,616	33,802	31,985	29,789	30,075	478,154
47	KWH - TOTAL	16,513,728	18,641,250	26,270,384	26,202,898	25,698,237	20,411,983	16,857,911	15,923,290	18,974,944	17,487,608	15,067,742	17,709,208	235,759,183
48	KWH - BASE RESOURCES	15,550,193	18,641,250	23,440,937	25,226,045	25,091,276	20,366,383	16,857,911	15,923,290	18,974,944	17,487,608	15,067,742	13,462,391	226,109,971
49	KWH - OTHER EXISTING RESOURCES	963,535	0	2,829,447	976,853	530,161	0	0	0	0	0	0	4,246,817	9,546,812
50	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	76,800	25,600	0	0	0	0	0	0	102,400
51														
52	PARTIAL REQUIREMENTS													
53	KW	349,228	427,980	492,397	470,446	474,082	454,766	396,218	318,983	351,067	341,573	336,181	301,595	4,714,516
54	KWH - TOTAL	190,914,639	207,246,632	228,768,256	240,209,639	240,629,433	217,572,523	193,617,635	165,046,349	184,221,024	177,384,911	158,640,997	164,452,558	2,368,704,596
55	KWH - BASE RESOURCES	125,986,466	196,635,172	193,580,372	202,444,905	204,086,654	194,808,354	177,344,709	158,592,167	174,348,178	165,355,446	149,053,374	103,364,555	2,045,600,355
56	KWH - OTHER EXISTING RESOURCES	64,928,173	10,611,460	35,187,884	37,764,734	34,219,579	21,989,769	16,272,926	6,454,182	9,872,845	12,029,465	9,587,623	61,088,003	320,006,641
57	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,323,200	774,400	0	0	0	0	0	0	3,097,600
58														
59	TOTAL CLASS A													
60	KW	379,766	473,019	549,916	526,516	527,636	502,073	432,078	345,599	384,889	373,558	365,970	331,670	5,192,670
61	KWH - TOTAL	207,428,367	225,887,882	255,038,640	266,412,537	266,327,670	237,984,506	210,475,546	180,969,639	203,195,968	194,872,519	173,708,739	182,161,766	2,604,463,779
62	KWH - BASE RESOURCES	141,536,659	215,276,422	217,021,309	227,670,950	229,177,930	215,194,737	194,202,620	174,515,457	193,323,123	182,843,054	164,121,116	116,826,946	2,271,710,326
63	KWH - OTHER EXISTING RESOURCES	65,891,708	10,611,460	38,017,331	38,741,587	34,749,740	21,989,769	16,272,926	6,454,182	9,872,845	12,029,465	9,587,623	65,334,820	329,553,453
64	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,400,000	800,000	0	0	0	0	0	0	3,200,000

Arizona Electric Power Cooperative, Inc.

ANZA ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	6,468	6,132	9,936	11,832	10,716	9,036	5,592	6,564	9,156	7,440	7,596	6,408	96,876
3	kW - Current Year	5,712	7,488	10,608	10,404	9,948	9,684	6,852	5,388	8,860	8,093	7,071	6,304	96,412
4	kW - 12 Month Average	8,010	8,123	8,179	8,060	7,996	8,050	8,155	8,057	8,032	8,087	8,043	8,034	96,826
5	ARM Load Ratio Share	20.19%	20.31%	20.41%	20.15%	20.01%	19.97%	20.29%	20.12%	20.13%	20.26%	20.23%	20.16%	20.19%
6	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
7	KWH - BASE RESOURCES	3,516,089	3,974,280	4,058,041	5,070,048	4,966,884	4,304,383	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	3,076,659	49,283,270
8	KWH - OTHER EXISTING RESOURCES	217,867	0	489,827	196,332	104,947	0	0	0	0	0	0	970,556	1,979,530
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	15,203	5,405	0	0	0	0	0	0	20,608
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$85,566	$112,170	$158,908	$155,852	$149,021	$145,066	$102,643	$80,712	$132,723	$121,233	$105,924	$94,434	$1,444,252
19	Base Energy Charge Revenue	77,405	82,387	94,277	109,172	105,454	89,342	80,051	76,346	97,075	85,544	82,153	83,899	1,063,105
20	Total Present Base Rate Revenue	$162,971	$194,557	$253,185	$265,024	$254,475	$234,408	$182,694	$157,058	$229,797	$206,777	$188,077	$178,333	$2,507,357
21	FPPCA	47,496	50,553	67,127	77,732	75,085	63,612	103,259	98,480	125,218	110,345	105,971	108,223	1,033,100
22	Total Present Revenue	$210,467	$245,110	$320,312	$342,756	$329,560	$298,021	$285,953	$255,539	$355,016	$317,122	$294,048	$286,555	$3,540,457
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$48,215	$48,496	$48,747	$48,128	$47,787	$47,691	$48,444	$48,038	$48,070	$48,385	$48,296	$48,149	$578,447
34	O&M Demand Charge Revenue	83,595	84,083	84,517	83,445	82,854	82,687	83,992	83,288	83,344	83,890	83,736	83,480	1,002,912
35	Base Resource Energy Revenue	110,960	125,420	128,063	160,000	156,744	135,837	121,863	116,224	147,779	130,226	125,064	97,093	1,555,271
36	Other Existing Resources Energy Revenue	13,442	0	30,221	12,113	6,475	0	0	0	0	0	0	59,880	122,130
37	Additional ARM Resources	0	0	0	0	938	333	0	0	0	0	0	0	1,271
38	Total Proposed Base Rate Revenue	$256,212	$257,998	$291,547	$303,686	$294,798	$266,549	$254,300	$247,550	$279,193	$262,501	$257,097	$288,601	$3,260,032
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$256,212	$257,998	$291,547	$303,686	$294,798	$266,549	$254,300	$247,550	$279,193	$262,501	$257,097	$288,601	$3,260,032
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$46,245	$20,409	($25,644)	($24,279)	($18,380)	($14,687)	$29,794	$50,614	($1,309)	$11,042	$26,109	$37,195	$137,108
44	Change in Base Energy Charge Revenue	46,997	43,033	64,006	62,940	58,703	46,828	41,812	39,878	50,704	44,682	42,911	73,074	615,568
45	Change in Base Rate Revenue	$93,241	$63,441	$38,362	$38,662	$40,323	$32,141	$71,606	$90,491	$49,395	$55,724	$69,020	$110,269	$752,675
46	Change in FPPCA Revenue	(47,496)	(50,553)	(67,127)	(77,732)	(75,085)	(63,612)	(103,259)	(98,480)	(125,218)	(110,345)	(105,971)	(108,223)	(1,033,100)
47	Change in Total Revenue	$45,745	$12,888	($28,764)	($39,070)	($34,762)	($31,471)	($31,653)	($7,989)	($75,823)	($54,621)	($36,951)	$2,046	($280,425)
48	Percentage Change in Base Rate Revenue	57.21%	32.61%	15.15%	14.59%	15.85%	13.71%	39.19%	57.62%	21.50%	26.95%	36.70%	61.83%	30.02%
49	Percentage Change in Total Revenue	21.74%	5.26%	-8.98%	-11.40%	-10.55%	-10.56%	-11.07%	-3.13%	-21.36%	-17.22%	-12.57%	0.71%	-7.92%

Arizona Electric Power Cooperative, Inc.

DUNCAN ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	3,100	5,640	6,660	6,020	6,520	3,720	4,520	3,320	4,520	4,320	4,180	3,260	55,780
3	kW - Current Year	3,860	6,040	6,960	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
4	kW - 12 Month Average	4,712	4,745	4,770	4,763	4,772	4,908	4,867	4,822	4,803	4,768	4,745	4,765	57,440
5	ARM Load Ratio Share	11.88%	11.86%	11.91%	11.91%	11.94%	12.18%	12.11%	12.04%	12.04%	11.95%	11.93%	11.96%	11.98%
6	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
7	KWH - BASE RESOURCES	1,887,693	2,422,840	2,876,180	2,850,055	2,886,066	2,297,715	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,508,562	26,956,670
8	KWH - OTHER EXISTING RESOURCES	116,967	0	347,170	110,365	60,981	0	0	0	0	0	0	475,888	1,111,371
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	8,834	2,885	0	0	0	0	0	0	11,719
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$57,823	$90,479	$104,261	$88,981	$99,168	$80,293	$60,220	$41,644	$64,414	$58,422	$58,422	$52,430	$856,556
19	Base Energy Charge Revenue	41,557	50,225	66,820	61,370	61,275	47,691	39,792	39,508	47,516	46,158	39,043	41,138	582,093
20	Total Present Base Rate Revenue	$99,379	$140,705	$171,081	$150,351	$160,443	$127,984	$100,012	$81,153	$111,930	$104,580	$97,465	$93,568	$1,438,650
21	FPPCA	25,499	30,819	47,577	43,696	43,629	33,957	51,329	50,962	61,291	59,540	50,362	53,064	551,725
22	Total Present Revenue	$124,879	$171,523	$218,657	$194,047	$204,072	$161,941	$151,341	$132,115	$173,221	$164,121	$147,827	$146,632	$1,990,375
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$28,361	$28,329	$28,429	$28,443	$28,518	$29,079	$28,910	$28,748	$28,746	$28,530	$28,493	$28,556	$343,141
34	O&M Demand Charge Revenue	49,173	49,116	49,290	49,315	49,444	50,417	50,124	49,843	49,840	49,465	49,401	49,510	594,938
35	Base Resource Energy Revenue	59,571	76,459	90,766	89,941	91,078	72,511	60,577	60,144	72,334	70,268	59,436	47,607	850,693
36	Other Existing Resources Energy Revenu	7,216	0	21,419	6,809	3,762	0	0	0	0	0	0	29,361	68,568
37	Additional ARM Resources	0	0	0	0	545	178	0	0	0	0	0	0	723
38	Total Proposed Base Rate Revenue	$144,322	$153,905	$189,905	$174,508	$173,346	$152,185	$139,611	$138,736	$150,920	$148,263	$137,329	$155,034	$1,858,063
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$144,322	$153,905	$189,905	$174,508	$173,346	$152,185	$139,611	$138,736	$150,920	$148,263	$137,329	$155,034	$1,858,063
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$19,711	($13,034)	($26,541)	($11,223)	($21,206)	($797)	$18,815	$36,947	$14,171	$19,574	$19,471	$25,636	$81,523
44	Change in Base Energy Charge Revenue	25,231	26,234	45,365	35,381	34,110	24,997	20,785	20,636	24,819	24,110	20,393	35,830	337,890
45	Change in Base Rate Revenue	$44,942	$13,200	$18,824	$24,158	$12,903	$24,201	$39,599	$57,583	$38,990	$43,683	$39,864	$61,466	$419,414
46	Change in FPPCA Revenue	(25,499)	(30,819)	(47,577)	(43,696)	(43,629)	(33,957)	(51,329)	(50,962)	(61,291)	(59,540)	(50,362)	(53,064)	(551,725)
47	Change in Total Revenue	$19,443	($17,619)	($28,753)	($19,538)	($30,725)	($9,756)	($11,730)	$6,621	($22,301)	($15,857)	($10,498)	$8,402	($132,311)
48	Percentage Change in Base Rate Reveni	45.22%	9.38%	11.00%	16.07%	8.04%	18.91%	39.59%	70.96%	34.83%	41.77%	40.90%	65.69%	29.15%
49	Percentage Change in Total Revenue	15.57%	-10.27%	-13.15%	-10.07%	-15.06%	-6.02%	-7.75%	5.01%	-12.87%	-9.68%	-7.10%	5.73%	-6.65%

Arizona Electric Power Cooperative, Inc.

GRAHAM ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	21,235	29,349	40,099	39,125	36,733	30,341	27,052	18,498	21,918	20,119	19,731	19,458	323,658
3	kW - Current Year	20,966	31,511	39,951	39,726	36,986	32,263	24,988	18,448	20,642	19,992	18,818	20,271	324,562
4	kW - 12 Month Average	26,949	27,129	27,117	27,167	27,188	27,348	27,176	27,172	27,066	27,055	26,979	27,047	325,394
5	ARM Load Ratio Share	67.93%	67.83%	67.68%	67.93%	68.05%	67.85%	67.61%	67.84%	67.83%	67.79%	67.84%	67.88%	67.84%
6	KWH - TOTAL	10,775,112	12,244,130	18,499,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
7	KWH - BASE RESOURCES	10,146,411	12,244,130	16,506,717	17,305,943	17,238,326	13,784,286	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	8,877,170	149,870,030
8	KWH - OTHER EXISTING RESOURCES	628,701	0	1,992,449	670,155	364,234	(0)	0	0	0	0	0	2,800,373	6,455,912
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	52,763	17,309	0	0	0	0	0	0	70,073
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$314,071	$472,035	$598,466	$595,095	$554,050	$483,300	$374,320	$276,351	$309,217	$299,480	$281,894	$303,660	$4,861,939
19	Base Energy Charge Revenue	223,368	253,821	383,488	372,645	365,995	286,107	229,621	214,235	248,760	230,816	191,158	242,075	3,242,089
20	Total Present Base Rate Revenue	$537,439	$725,856	$981,954	$967,740	$920,045	$769,407	$603,942	$490,586	$557,978	$530,296	$473,052	$545,735	$8,104,028
21	FPPCA	137,059	155,745	273,048	265,327	260,593	203,712	296,193	276,346	320,881	297,733	246,578	312,257	3,045,472
22	Total Present Revenue	$674,498	$881,601	$1,255,001	$1,233,067	$1,180,638	$973,118	$900,134	$766,932	$878,858	$828,029	$719,630	$857,993	$11,149,500
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$162,216	$161,968	$161,617	$162,221	$162,488	$162,022	$161,438	$162,007	$161,977	$161,878	$162,003	$162,088	$1,943,922
34	O&M Demand Charge Revenue	281,251	280,820	280,211	281,259	281,721	280,914	279,902	280,887	280,835	280,663	280,882	281,028	3,370,373
35	Base Resource Energy Revenue	320,198	386,398	520,916	546,137	544,003	435,002	349,558	326,136	378,694	351,376	291,005	280,144	4,729,567
36	Other Existing Resources Energy Revenu	38,789	0	122,927	41,346	22,472	(0)	0	0	0	0	0	172,773	398,307
37	Additional ARM Resources	0	0	0	0	3,255	1,068	0	0	0	0	0	0	4,323
38	Total Proposed Base Rate Revenue	$802,454	$829,185	$1,085,670	$1,030,964	$1,013,939	$879,006	$790,898	$769,030	$821,506	$793,917	$733,890	$896,033	$10,446,493
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$802,454	$829,185	$1,085,670	$1,030,964	$1,013,939	$879,006	$790,898	$769,030	$821,506	$793,917	$733,890	$896,033	$10,446,493
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$129,396	($29,247)	($156,638)	($151,615)	($109,842)	($40,364)	$67,020	$166,543	$133,595	$143,061	$160,991	$139,456	$452,356
44	Change in Base Energy Charge Revenue	135,619	132,577	260,355	214,839	203,736	149,962	119,937	111,900	129,934	120,561	99,847	210,842	1,890,108
45	Change in Base Rate Revenue	$265,015	$103,329	$103,717	$63,224	$93,894	$109,599	$186,957	$278,443	$263,528	$263,621	$260,838	$350,298	$2,342,464
46	Change in FPPCA Revenue	(137,059)	(155,745)	(273,048)	(265,327)	(260,593)	(203,712)	(296,193)	(276,346)	(320,881)	(297,733)	(246,578)	(312,257)	(3,045,472)
47	Change in Total Revenue	$127,956	($52,416)	($169,331)	($202,103)	($166,698)	($94,113)	($109,236)	$2,097	($57,352)	($34,112)	$14,260	$38,041	($703,008)
48	Percentage Change in Base Rate Revenu	49.31%	14.24%	10.56%	6.53%	10.21%	14.24%	30.96%	56.76%	47.23%	49.71%	55.14%	64.19%	28.90%
49	Percentage Change in Total Revenue	18.97%	-5.95%	-13.49%	-16.39%	-14.12%	-9.67%	-12.14%	0.27%	-6.53%	-4.12%	1.98%	4.43%	-6.31%

Arizona Electric Power Cooperative, Inc.

MOHAVE ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.011050	$0.011050	$0.013050	$0.013050	$0.013050	$0.013050	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$855,113	$855,113	$855,113	$855,113	$855,113	$841,539	$855,113	$855,113	$855,113	$841,248	$855,113	$841,405	$10,220,208
7														
8	**PRESENT REVENUES**													
9	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
10	KWH - BASE RESOURCES	50,755,139	78,652,286	76,388,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
11	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,679,515
12	Demand Revenue	$1,814,798	$2,046,290	$2,167,510	$2,168,113	$2,167,010	$2,131,670	$1,926,246	$1,646,083	$1,719,895	$1,680,468	$1,698,967	$1,565,038	$22,732,087
13	Base Energy Charge Revenue	1,612,943	1,703,368	1,755,123	1,919,342	1,913,881	1,723,372	1,527,516	1,243,970	1,322,828	1,241,118	1,096,053	1,087,114	18,146,629
14	Total Present Base Rate Revenue	$3,427,741	$3,749,659	$3,922,633	$4,087,455	$4,080,891	$3,855,042	$3,453,762	$2,890,053	$3,042,723	$2,921,585	$2,795,020	$2,652,152	$40,878,716
15	FPPCA	859,770	907,970	1,104,889	1,208,269	1,204,831	1,084,901	1,879,736	1,530,809	1,627,850	1,527,299	1,348,785	1,337,785	15,622,895
16	Total Present Revenue	$4,287,511	$4,657,629	$5,027,522	$5,295,725	$5,285,722	$4,939,943	$5,333,498	$4,420,862	$4,670,573	$4,448,884	$4,143,805	$3,989,937	$56,501,611
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	
20	O&M Demand Charge	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	
21	Base Resource Energy Charge	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	
22	Other Existing Resources Energy Charge	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$8,727,401
27	O&M Demand Charge Revenue	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	15,298,589
28	Base Resource Energy Revenue	1,631,645	2,528,466	2,455,622	2,594,195	2,612,518	2,472,658	2,217,326	1,887,770	2,008,670	1,871,542	1,673,996	1,271,666	25,226,075
29	Other Existing Resources Energy Revenu	1,860,829	241,921	569,519	817,930	760,603	427,710	324,157	88,450	91,425	113,708	55,049	886,267	6,237,567
30	Total Proposed Base Rate Revenue	$5,494,640	$4,772,552	$5,027,307	$5,414,290	$5,375,287	$4,902,534	$4,543,649	$3,978,386	$4,102,261	$3,987,416	$3,731,210	$4,160,099	$55,489,632
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$5,494,640	$4,772,552	$5,027,307	$5,414,290	$5,375,287	$4,902,534	$4,543,649	$3,978,386	$4,102,261	$3,987,416	$3,731,210	$4,160,099	$55,489,632
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$187,368	($44,124)	($165,345)	($165,947)	($164,844)	($129,504)	$75,920	$356,083	$282,271	$321,698	$303,199	$437,128	$1,293,903
36	Change in Energy Charge Revenue	1,879,531	1,067,018	1,270,019	1,492,782	1,459,239	1,176,997	1,013,968	732,250	777,267	744,133	632,991	1,070,819	13,317,014
37	Change in Base Rate Revenue	$2,066,899	$1,022,894	$1,104,674	$1,326,835	$1,294,396	$1,047,493	$1,089,887	$1,088,333	$1,059,538	$1,065,831	$936,190	$1,507,947	$14,610,916
38	Change in FPPCA Revenue	(859,770)	(907,970)	(1,104,889)	(1,208,269)	(1,204,831)	(1,084,901)	(1,879,736)	(1,530,809)	(1,627,850)	(1,527,299)	(1,348,785)	(1,337,785)	(15,622,895)
39	Change in Total Revenue	$1,207,129	$114,923	($215)	$118,566	$89,564	($37,409)	($789,849)	($442,476)	($568,313)	($461,468)	($412,595)	$170,162	($1,011,979)
40	Percentage Change in Base Rate Revenu	60.30%	27.28%	28.16%	32.46%	31.72%	27.17%	31.56%	37.66%	34.82%	36.48%	33.49%	56.86%	35.74%
41	Percentage Change in Total Revenue	28.15%	2.47%	0.00%	2.24%	1.69%	-0.76%	-14.81%	-10.01%	-12.17%	-10.37%	-9.96%	4.26%	-1.79%

Arizona Electric Power Cooperative, Inc.

SULPHUR SPRINGS ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.011050	$0.011050	$0.013050	$0.013050	$0.013050	$0.013050	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$9,089,148
7														
8	**PRESENT REVENUES**													
9	KW	131,134	137,934	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	138,700	128,900	1,629,806
10	KWH - BASE RESOURCES	45,109,060	71,215,789	67,765,404	69,476,926	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	38,296,091	738,282,902
11	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
12	Demand Revenue	$1,709,462	$1,758,830	$1,824,896	$1,771,898	$1,757,378	$1,744,310	$1,716,722	$1,616,534	$1,784,966	$1,778,911	$1,764,391	$1,693,243	$20,921,540
13	Base Energy Charge Revenue	1,446,096	1,558,774	1,553,892	1,562,858	1,569,492	1,501,590	1,434,581	1,287,408	1,460,597	1,440,640	1,326,890	1,416,282	17,559,098
14	Total Present Base Rate Revenue	$3,155,558	$3,317,604	$3,378,788	$3,334,756	$3,326,869	$3,245,900	$3,151,303	$2,903,941	$3,245,563	$3,219,551	$3,091,281	$3,109,525	$38,480,637
15	FPPCA	770,833	830,895	978,210	983,854	988,030	945,285	1,765,372	1,584,263	1,797,387	1,772,828	1,632,849	1,742,853	15,792,657
16	Total Present Revenue	$3,926,390	$4,148,499	$4,356,997	$4,318,610	$4,314,899	$4,191,184	$4,916,674	$4,488,204	$5,042,949	$4,992,378	$4,724,130	$4,852,378	$54,273,295
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	
20	O&M Demand Charge	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	
21	Base Resource Energy Charge	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	
22	Other Existing Resources Energy Charge	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$7,727,894
27	O&M Demand Charge Revenue	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	13,546,516
28	Base Resource Energy Revenue	1,456,357	2,299,219	2,187,822	2,243,079	2,266,032	2,208,312	2,056,423	1,889,857	2,093,151	2,030,752	1,868,240	1,236,399	23,835,642
29	Other Existing Resources Energy Revenu	1,645,489	265,575	480,184	394,804	368,707	269,395	367,667	238,139	375,504	440,258	409,980	2,004,284	7,259,986
30	Total Proposed Base Rate Revenue	$4,874,713	$4,337,661	$4,440,874	$4,410,751	$4,407,607	$4,250,575	$4,196,957	$3,900,864	$4,241,522	$4,243,877	$4,051,087	$5,013,550	$52,370,038
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$4,874,713	$4,337,661	$4,440,874	$4,410,751	$4,407,607	$4,250,575	$4,196,957	$3,900,864	$4,241,522	$4,243,877	$4,051,087	$5,013,550	$52,370,038
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$63,406	$14,038	($52,028)	$970	$15,490	$28,558	$56,146	$156,334	($12,098)	($6,044)	$8,476	$79,624	$352,870
36	Change in Energy Charge Revenue	1,655,750	1,006,020	1,114,115	1,075,026	1,065,248	976,117	989,509	840,589	1,008,058	1,030,370	951,329	1,824,400	13,536,530
37	Change in Base Rate Revenue	$1,719,156	$1,020,057	$1,062,087	$1,075,995	$1,080,737	$1,004,675	$1,045,655	$996,923	$995,959	$1,024,326	$959,806	$1,904,025	$13,889,401
38	Change in FPPCA Revenue	(770,833)	(830,895)	(978,210)	(983,854)	(988,030)	(945,285)	(1,765,372)	(1,584,263)	(1,797,387)	(1,772,828)	(1,632,849)	(1,742,853)	(15,792,657)
39	Change in Total Revenue	$948,323	$189,162	$83,877	$92,141	$92,707	$59,390	($719,717)	($587,340)	($801,427)	($748,501)	($673,043)	$161,171	($1,903,257)
40	Percentage Change in Base Rate Revenu	54.48%	30.75%	31.43%	32.27%	32.49%	30.95%	33.18%	34.33%	30.69%	31.82%	31.05%	61.23%	36.09%
41	Percentage Change in Total Revenue	24.15%	4.56%	1.93%	2.13%	2.15%	1.42%	-14.64%	-13.09%	-15.89%	-14.99%	-14.25%	3.32%	-3.51%

Arizona Electric Power Cooperative, Inc.

TRICO ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	88,830	110,939	146,640	163,888	146,704	139,833	110,067	87,080	92,923	87,572	84,462	69,545	1,328,483
3	kW - Current Year	85,906	125,972	164,592	149,858	155,646	141,128	116,545	91,700	90,417	85,278	81,248	73,021	1,361,311
4	kW - 12 Month Average	110,463	111,716	113,212	112,043	112,788	112,896	113,436	113,821	113,612	113,421	113,153	113,443	1,354,003
5	ARM Load Ratio Share	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	KWH - TOTAL	43,348,839	49,883,272	69,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
7	KWH - BASE RESOURCES	30,122,267	46,767,098	49,428,600	52,271,075	52,631,923	49,492,013	44,675,503	41,333,563	47,031,999	44,237,586	39,114,179	25,511,101	522,616,908
8	KWH - OTHER EXISTING RESOURCES	13,226,572	3,116,174	19,715,226	19,959,774	17,638,950	11,736,310	6,052,772	1,600,986	2,918,665	3,781,325	2,645,818	18,179,457	120,572,028
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,323,200	774,400	0	0	0	0	0	0	3,097,600
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$1,286,872	$1,887,061	$2,465,588	$2,244,873	$2,331,577	$2,114,097	$1,745,844	$1,373,666	$1,354,447	$1,277,464	$1,217,095	$1,093,855	$20,392,439
19	Base Energy Charge Revenue	898,621	1,034,080	1,433,352	1,497,345	1,504,875	1,285,316	1,051,597	890,033	1,035,477	995,432	865,685	905,705	13,397,520
20	Total Present Base Rate Revenue	$2,185,493	$2,921,141	$3,898,940	$3,742,218	$3,836,452	$3,399,414	$2,797,441	$2,263,699	$2,389,924	$2,272,896	$2,082,780	$1,999,560	$33,789,959
21	FPPCA	551,397	634,515	1,020,563	1,066,127	1,071,489	915,160	1,356,474	1,148,070	1,335,681	1,284,026	1,116,662	1,168,286	12,668,450
22	Total Present Revenue	$2,736,891	$3,555,656	$4,919,503	$4,808,346	$4,907,941	$4,314,574	$4,153,915	$3,411,769	$3,725,605	$3,556,922	$3,199,442	$3,167,845	$46,458,408
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	
26	O&M Demand Charge	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	
27	Base Resource Energy Charge	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	
28	Other Existing Resources Energy Charge	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	
29	Additional ARM Resources	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$7,757,219
34	O&M Demand Charge Revenue	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	9,173,582
35	Base Resource Energy Revenue	975,449	1,514,458	1,600,645	1,692,693	1,704,378	1,602,698	1,446,726	1,338,504	1,523,036	1,432,544	1,266,633	826,125	16,923,888
36	Other Existing Resources Energy Revenue	873,507	205,798	1,302,030	1,318,181	1,164,909	775,088	399,736	105,732	192,754	249,726	174,735	1,200,605	7,962,802
37	Additional ARM Resources	0	0	0	0	153,428	51,143	0	0	0	0	0	0	204,571
38	Total Proposed Base Rate Revenue	$3,259,856	$3,131,156	$4,313,575	$4,421,774	$4,433,616	$3,839,829	$3,257,362	$2,855,136	$3,126,690	$3,093,170	$2,852,268	$3,437,631	$42,022,063
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$3,259,856	$3,131,156	$4,313,575	$4,421,774	$4,433,616	$3,839,829	$3,257,362	$2,855,136	$3,126,690	$3,093,170	$2,852,268	$3,437,631	$42,022,063
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$124,028	($476,160)	($1,054,688)	($833,973)	($920,677)	($703,197)	($334,944)	$37,234	$56,453	$133,436	$193,805	$317,046	($3,461,637)
44	Change in Base Energy Charge Revenue	950,335	686,175	1,469,324	1,513,528	1,517,841	1,143,613	794,865	554,202	680,313	686,838	575,683	1,121,025	11,693,741
45	Change in Base Rate Revenue	$1,074,363	$210,015	$414,636	$679,555	$597,164	$440,415	$459,921	$591,437	$736,766	$820,274	$769,488	$1,438,071	$8,232,104
46	Change in FPPCA Revenue	(551,397)	(634,515)	(1,020,563)	(1,066,127)	(1,071,489)	(915,160)	(1,356,474)	(1,148,070)	(1,335,681)	(1,284,026)	(1,116,662)	(1,168,286)	(12,668,450)
47	Change in Total Revenue	$522,966	($424,500)	($605,927)	($386,572)	($474,325)	($474,745)	($896,553)	($556,633)	($598,915)	($463,752)	($347,174)	$269,785	($4,436,346)
48	Percentage Change in Base Rate Revenue	49.16%	7.19%	10.63%	18.16%	15.57%	12.96%	16.44%	26.13%	30.83%	36.09%	36.95%	71.92%	24.36%
49	Percentage Change in Total Revenue	19.11%	-11.94%	-12.32%	-8.04%	-9.66%	-11.00%	-21.58%	-16.32%	-16.08%	-13.04%	-10.85%	8.52%	-9.55%

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	PRESENT REVENUES													
2	FULL REQUIREMENTS													
3	Demand Revenue	$457,459	$674,684	$861,635	$839,929	$802,239	$708,659	$537,183	$398,708	$506,354	$479,135	$446,239	$450,524	$7,162,747
4	Base Energy Revenue	342,330	386,433	544,585	543,186	532,724	423,140	349,464	330,090	393,351	362,518	312,354	367,112	4,887,288
5	Total Present Base Rate Revenue	$799,789	$1,061,117	$1,406,220	$1,383,115	$1,334,963	$1,131,799	$886,647	$728,797	$899,705	$841,653	$758,594	$817,635	$12,050,035
6	FPPCA	210,055	237,117	387,751	386,755	379,306	301,281	450,781	425,789	507,390	467,619	402,911	473,544	4,630,297
7	Total Adjusted Present Revenue	$1,009,843	$1,298,234	$1,793,971	$1,769,869	$1,714,269	$1,433,080	$1,337,428	$1,154,586	$1,407,095	$1,309,272	$1,161,505	$1,291,180	$16,680,332
8														
9	PARTIAL REQUIREMENTS													
10	Fixed / O&M Charge Revenue	$4,811,132	$5,692,181	$6,457,994	$6,184,884	$6,255,964	$5,990,077	$5,388,812	$4,636,283	$4,859,308	$4,736,843	$4,680,453	$4,352,135	$64,046,066
11	Base Energy Revenue	3,957,660	4,296,223	4,742,366	4,979,546	4,988,248	4,510,278	4,013,694	3,421,411	3,818,902	3,677,189	3,288,628	3,409,102	49,103,246
12	Total Present Base Rate Revenue	$8,768,792	$9,988,403	$11,200,360	$11,164,430	$11,244,213	$10,500,356	$9,402,506	$8,057,693	$8,678,209	$8,414,032	$7,969,081	$7,761,237	$113,149,312
13	FPPCA	2,181,999	2,373,380	3,103,662	3,258,251	3,264,350	2,945,346	5,001,582	4,263,142	4,760,918	4,584,152	4,098,297	4,248,924	44,084,002
14	Total Adjusted Present Revenue	$10,950,791	$12,361,784	$14,304,022	$14,422,680	$14,508,563	$13,445,702	$14,404,087	$12,320,835	$13,439,127	$12,998,185	$12,067,377	$12,010,161	$157,233,314
15														
16	TOTAL CLASS A													
17	Demand Revenue	$5,268,591	$6,366,865	$7,319,629	$7,024,812	$7,058,203	$6,698,736	$5,925,995	$5,034,990	$5,365,662	$5,215,978	$5,126,692	$4,802,659	$71,208,813
18	Base Energy Revenue	4,299,990	4,682,656	5,286,951	5,522,732	5,520,973	4,933,419	4,363,158	3,751,501	4,212,252	4,039,707	3,600,982	3,776,213	53,990,534
19	Total Present Base Rate Revenue	$9,568,581	$11,049,521	$12,606,580	$12,547,544	$12,579,176	$11,632,155	$10,289,153	$8,786,491	$9,577,914	$9,255,686	$8,727,674	$8,578,872	$125,199,347
20	FPPCA	2,392,054	2,610,497	3,491,413	3,645,005	3,643,656	3,246,627	5,452,362	4,688,931	5,268,308	5,051,771	4,501,208	4,722,468	48,714,300
21	Total Adjusted Present Revenue	$11,960,635	$13,660,018	$16,097,993	$16,192,550	$16,222,832	$14,878,782	$15,741,515	$13,475,422	$14,846,222	$14,307,457	$13,228,882	$13,301,341	$173,913,646
22														
23	PROPOSED REVENUES													
24	FULL REQUIREMENTS													
25	Demand Revenue	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$7,833,734
26	Base Energy Revenue	550,177	588,277	914,311	856,347	829,273	644,929	531,998	502,504	598,807	551,870	475,505	686,857	7,730,854
27	Total Proposed Base Rate Revenue	$1,202,988	$1,241,088	$1,567,122	$1,509,158	$1,482,084	$1,297,740	$1,184,810	$1,155,315	$1,251,618	$1,204,681	$1,128,316	$1,339,668	$15,564,588
28	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total Adjusted Proposed Revenue	$1,202,988	$1,241,088	$1,567,122	$1,509,158	$1,482,084	$1,297,740	$1,184,810	$1,155,315	$1,251,618	$1,204,681	$1,128,316	$1,339,668	$15,564,588
30														
31	PARTIAL REQUIREMENTS													
32	Fixed / O&M Charge Revenue	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$62,231,201
33	Base Energy Revenue	8,443,276	7,055,436	8,595,823	9,060,881	9,030,576	7,807,005	6,812,035	5,548,452	6,284,539	6,138,530	5,448,632	7,425,346	87,650,532
34	Total Proposed Base Rate Revenue	$13,629,209	$12,241,369	$13,781,757	$14,246,815	$14,216,509	$12,992,938	$11,997,969	$10,734,386	$11,470,473	$11,324,464	$10,634,565	$12,611,280	$149,881,733
35	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total Adjusted Proposed Revenue	$13,629,209	$12,241,369	$13,781,757	$14,246,815	$14,216,509	$12,992,938	$11,997,969	$10,734,386	$11,470,473	$11,324,464	$10,634,565	$12,611,280	$149,881,733
37														
38	TOTAL CLASS A													
39	Demand Revenue	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$70,064,935
40	Base Energy Revenue	8,993,452	7,643,712	9,510,135	9,917,228	9,859,848	8,451,934	7,344,034	6,050,956	6,883,347	6,690,400	5,924,137	8,112,203	95,381,386
41	Total Proposed Base Rate Revenue	$14,832,197	$13,482,457	$15,348,879	$15,755,973	$15,698,593	$14,290,678	$13,182,778	$11,889,701	$12,722,091	$12,529,145	$11,762,881	$13,950,948	$165,446,321
42	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Adjusted Proposed Revenue	$14,832,197	$13,482,457	$15,348,879	$15,755,973	$15,698,593	$14,290,678	$13,182,778	$11,889,701	$12,722,091	$12,529,145	$11,762,881	$13,950,948	$165,446,321
44														
45	PROPOSED REVENUE CHANGES													
46	FULL REQUIREMENTS													
47	Demand Revenue	$195,352	($21,873)	($208,823)	($187,117)	($149,428)	($55,848)	$115,628	$254,103	$146,457	$173,676	$206,572	$202,288	$670,987
48	Base Energy Revenue	207,847	201,844	369,726	313,161	296,548	221,788	182,534	172,414	205,457	189,352	163,150	319,745	2,843,566
49	Change in Base Rate Revenue	$403,199	$179,971	$160,903	$126,043	$147,120	$165,941	$298,162	$426,518	$351,914	$363,028	$369,722	$522,033	$3,514,553
50	FPPCA	(210,055)	(237,117)	(387,751)	(386,755)	(379,306)	(301,281)	(450,781)	(425,789)	(507,390)	(467,619)	(402,911)	(473,544)	(4,630,297)
51	Total Revenue Change	$193,144	($57,146)	($226,848)	($260,712)	($232,186)	($135,340)	($152,618)	$729	($155,476)	($104,591)	($33,189)	$48,489	($1,115,744)
52	Percent Change in Base Rate Revenue	4.60%	1.80%	1.44%	1.13%	1.31%	1.58%	3.17%	5.29%	4.06%	4.31%	4.64%	6.73%	3.11%
53	Percent Change in Total Revenue	19.13%	-4.40%	-12.65%	-14.73%	-13.54%	-9.44%	-11.41%	0.06%	-11.05%	-7.99%	-2.86%	3.76%	-6.69%
54														
55	PARTIAL REQUIREMENTS													
56	Fixed / O&M Charge Revenue	$374,802	($506,247)	($1,272,061)	($998,950)	($1,070,031)	($804,144)	($202,879)	$549,651	$326,626	$449,090	$505,481	$833,798	($1,814,864)
57	Base Energy Revenue	4,485,615	2,759,213	3,853,458	4,081,336	4,042,327	3,296,726	2,798,342	2,127,042	2,465,637	2,461,341	2,160,004	4,016,245	38,547,286
58	Change in Base Rate Revenue	$4,860,417	$2,252,966	$2,581,397	$3,082,385	$2,972,296	$2,492,583	$2,595,463	$2,676,692	$2,792,263	$2,910,431	$2,665,485	$4,850,043	$36,732,421
59	FPPCA	(2,181,999)	(2,373,380)	(3,103,662)	(3,258,251)	(3,264,350)	(2,945,346)	(5,001,582)	(4,263,142)	(4,760,918)	(4,584,152)	(4,098,297)	(4,248,924)	(44,084,002)
60	Total Revenue Change	$2,678,418	($120,414)	($522,265)	($175,865)	($292,054)	($452,763)	($2,406,119)	($1,586,449)	($1,968,654)	($1,673,721)	($1,432,812)	$601,118	($7,351,581)
61	Percent Change in Base Rate Revenue	55.43%	22.56%	23.05%	27.61%	26.43%	23.74%	27.60%	33.22%	32.18%	34.59%	33.45%	62.49%	32.46%
62	Percent Change in Total Revenue	24.46%	-0.97%	-3.65%	-1.22%	-2.01%	-3.37%	-16.70%	-12.88%	-14.65%	-12.88%	-11.87%	5.01%	-4.68%
63														
64	TOTAL CLASS A													
65	Demand Revenue	$570,154	($528,120)	($1,480,884)	($1,186,068)	($1,219,459)	($859,991)	($87,250)	$803,754	$473,083	$622,766	$712,053	$1,036,086	($1,143,877)
66	Base Energy Revenue	4,693,462	2,961,057	4,223,184	4,394,496	4,338,876	3,518,515	2,980,675	2,299,456	2,671,094	2,650,693	2,323,154	4,335,990	41,390,852
67	Percent Change in Base Rate Revenue	$5,263,616	$2,432,936	$2,742,299	$3,208,429	$3,119,417	$2,658,523	$2,893,625	$3,103,210	$3,144,177	$3,273,459	$3,035,207	$5,372,076	$40,246,975
68	FPPCA	(2,392,054)	(2,610,497)	(3,491,413)	(3,645,005)	(3,643,656)	(3,246,627)	(5,452,362)	(4,688,931)	(5,268,308)	(5,051,771)	(4,501,208)	(4,722,468)	(48,714,300)
69	Total Revenue Change	$2,871,562	($177,561)	($749,113)	($436,577)	($524,239)	($588,104)	($2,558,737)	($1,585,721)	($2,124,130)	($1,778,312)	($1,466,001)	$649,607	($8,467,325)
70	Percent Change in Base Rate Revenue	55.01%	22.02%	21.75%	25.57%	24.80%	22.85%	28.12%	35.32%	32.83%	35.37%	34.78%	62.62%	32.15%
71	Percent Change in Total Revenue	24.01%	-1.30%	-4.65%	-2.70%	-3.23%	-3.95%	-16.25%	-11.77%	-14.31%	-12.43%	-11.08%	4.88%	-4.87%

Arizona Electric Power Cooperative, Inc.

ANALYSIS OF REVENUE BY DETAILED CLASS WITH ACTUAL FPPCA

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**AVERAGE COST PER KWH - PRESENT REVENUES**													
2	ANZA	$0.05637	$0.06167	$0.07043	$0.06508	$0.06478	$0.06915	$0.07405	$0.06939	$0.07581	$0.07685	$0.07420	$0.07080	$0.06904
3	DUNCAN	$0.06229	$0.07079	$0.06784	$0.06555	$0.06904	$0.07039	$0.07884	$0.06932	$0.07557	$0.07371	$0.07849	$0.07389	$0.07088
4	GRAHAM	$0.06260	$0.07200	$0.06784	$0.06859	$0.06687	$0.07051	$0.08126	$0.07421	$0.07324	$0.07437	$0.07804	$0.07347	$0.07129
5	MOHAVE	$0.05510	$0.05668	$0.05938	$0.05720	$0.05725	$0.05942	$0.07238	$0.07367	$0.07319	$0.07431	$0.07837	$0.07608	$0.06455
6	SULPHER	$0.05629	$0.05517	$0.05813	$0.05728	$0.05699	$0.05786	$0.07105	$0.07227	$0.07157	$0.07184	$0.07381	$0.07102	$0.06407
7	TRICO	$0.06314	$0.07128	$0.07115	$0.06657	$0.06761	$0.06959	$0.08189	$0.07946	$0.07459	$0.07407	$0.07661	$0.07251	$0.07189
8	AEPCO CLASS A	$0.05766	$0.06047	$0.06312	$0.06078	$0.06091	$0.06252	$0.07479	$0.07446	$0.07306	$0.07342	$0.07616	$0.07302	$0.06678
9														
10	**AVERAGE COST PER KWH - PROPOSED REVENUES**													
11	ANZA	$0.06862	$0.06492	$0.06411	$0.05766	$0.05795	$0.06185	$0.06585	$0.06722	$0.05962	$0.06361	$0.06487	$0.07131	$0.06357
12	DUNCAN	$0.07199	$0.06352	$0.05892	$0.05895	$0.05864	$0.06615	$0.07273	$0.07279	$0.06584	$0.06659	$0.07292	$0.07812	$0.06617
13	GRAHAM	$0.07447	$0.06772	$0.05869	$0.05735	$0.05743	$0.06369	$0.07140	$0.07441	$0.06846	$0.07130	$0.07959	$0.07673	$0.06680
14	MOHAVE	$0.07062	$0.05808	$0.05938	$0.05848	$0.05822	$0.05897	$0.06166	$0.06630	$0.06429	$0.06660	$0.07057	$0.07933	$0.06339
15	SULPHER	$0.06988	$0.05769	$0.05924	$0.05850	$0.05822	$0.05868	$0.06065	$0.06281	$0.06020	$0.06107	$0.06329	$0.07338	$0.06183
16	TRICO	$0.07520	$0.06277	$0.06239	$0.06122	$0.06107	$0.06193	$0.06421	$0.06650	$0.06260	$0.06442	$0.06830	$0.07868	$0.06502
17	AEPCO CLASS A	$0.07151	$0.05969	$0.06018	$0.05914	$0.05894	$0.06005	$0.06263	$0.06570	$0.06261	$0.06429	$0.06772	$0.07659	$0.06352

Arizona Electric Power Cooperative, Inc.

ANZA ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	6,468	6,132	9,936	11,832	10,716	9,036	5,592	6,564	9,156	7,440	7,596	6,408	96,876
3	kW - Current Year	5,712	7,488	10,608	10,404	9,948	9,684	6,852	5,388	8,860	8,093	7,071	6,304	96,412
4	kW - 12 Month Average	8,010	8,123	8,179	8,060	7,996	8,050	8,155	8,057	8,032	8,087	8,043	8,034	96,828
5	ARM Load Ratio Share	20.19%	20.31%	20.41%	20.15%	20.01%	19.97%	20.29%	20.12%	20.13%	20.26%	20.23%	20.16%	20.19%
6	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
7	KWH - BASE RESOURCES	3,516,089	3,974,280	4,058,041	5,070,048	4,966,884	4,304,383	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	3,076,659	49,283,270
8	KWH - OTHER EXISTING RESOURCES	217,867	0	489,827	196,332	104,947	0	0	0	0	0	0	970,556	1,979,530
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	15,203	5,405	0	0	0	0	0	0	20,608
10														
11	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - SYNCHRONIZATION	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$85,566	$112,170	$158,908	$155,852	$149,021	$145,066	$102,643	$80,712	$132,723	$121,233	$105,924	$94,434	$1,444,252
19	Base Energy Charge Revenue	77,405	82,387	94,277	109,172	105,454	89,342	80,051	76,346	97,075	85,544	82,153	83,899	1,063,105
20	Total Present Base Rate Revenue	$162,971	$194,557	$253,185	$265,024	$254,475	$234,408	$182,694	$157,058	$229,797	$206,777	$188,077	$178,333	$2,507,357
21	FPPCA	61,581	65,544	75,004	86,854	83,896	71,077	63,686	60,738	77,229	68,056	65,358	66,747	845,770
22	Total Present Revenue	$224,551	$260,101	$328,189	$351,878	$338,371	$305,486	$246,379	$217,797	$307,027	$274,833	$253,435	$245,080	$3,353,127
23														
24	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
25	Fixed Demand Charge	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	PPFAC	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
33	Fixed Demand Charge Revenue	$48,215	$48,496	$48,747	$48,128	$47,787	$47,691	$48,444	$48,038	$48,070	$48,385	$48,296	$48,149	$578,447
34	O&M Demand Charge Revenue	83,595	84,083	84,517	83,445	82,854	82,687	83,992	83,288	83,344	83,890	83,736	83,480	1,002,912
35	Base Resource Energy Revenue	110,960	125,420	128,063	160,000	156,744	135,837	121,863	116,224	147,779	130,226	125,064	97,093	1,555,271
36	Other Existing Resources Energy Revenue	13,442	0	30,221	12,113	6,475	0	0	0	0	0	0	59,880	122,130
37	Additional ARM Resources	0	0	0	0	938	333	0	0	0	0	0	0	1,271
38	Total Proposed Base Rate Revenue	$256,212	$257,998	$291,547	$303,686	$294,798	$266,549	$254,300	$247,550	$279,193	$262,501	$257,097	$288,601	$3,260,032
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$256,212	$257,998	$291,547	$303,686	$294,798	$266,549	$254,300	$247,550	$279,193	$262,501	$257,097	$288,601	$3,260,032
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$46,245	$20,409	($25,644)	($24,279)	($18,380)	($14,687)	$29,794	$50,614	($1,309)	$11,042	$26,109	$37,195	$137,108
44	Change in Base Energy Charge Revenue	46,997	43,033	64,006	62,940	58,703	46,828	41,812	39,878	50,704	44,682	42,911	73,074	615,568
45	Change in Base Rate Revenue	$93,241	$63,441	$38,362	$38,662	$40,323	$32,141	$71,606	$90,491	$49,395	$55,724	$69,020	$110,269	$752,675
46	Change in FPPCA Revenue	(61,581)	(65,544)	(75,004)	(86,854)	(83,896)	(71,077)	(63,686)	(60,738)	(77,229)	(68,056)	(65,358)	(66,747)	(845,770)
47	Change in Total Revenue	$31,661	($2,103)	($36,642)	($48,192)	($43,573)	($38,936)	$7,920	$29,753	($27,834)	($12,333)	$3,662	$43,522	($93,095)
48	Percentage Change in Base Rate Revenue	57.21%	32.61%	15.15%	14.59%	15.85%	13.71%	39.19%	57.62%	21.50%	26.95%	36.70%	61.83%	30.02%
49	Percentage Change in Total Revenue	14.10%	-0.81%	-11.16%	-13.70%	-12.88%	-12.75%	3.21%	13.66%	-9.07%	-4.49%	1.44%	17.76%	-2.78%

Arizona Electric Power Cooperative, Inc.

DUNCAN ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	3,100	5,640	6,660	6,020	6,520	3,720	4,520	3,320	4,520	4,320	4,180	3,260	55,780
3	kW - Current Year	3,860	6,040	6,960	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
4	kW - 12 Month Average	4,712	4,745	4,770	4,763	4,772	4,908	4,867	4,822	4,803	4,768	4,745	4,765	57,440
5	ARM Load Ratio Share	11.88%	11.86%	11.91%	11.91%	11.94%	12.18%	12.11%	12.04%	12.04%	11.95%	11.93%	11.96%	11.98%
6	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
7	KWH - BASE RESOURCES	1,887,693	2,422,840	2,876,180	2,850,055	2,886,066	2,297,715	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,508,562	26,956,670
8	KWH - OTHER EXISTING RESOURCES	116,967	0	347,170	110,365	60,981	0	0	0	0	0	0	475,888	1,111,371
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	8,834	2,885	0	0	0	0	0	0	11,719
10														
11	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$57,823	$90,479	$104,261	$88,981	$99,168	$80,293	$60,220	$41,644	$64,414	$58,422	$58,422	$52,430	$856,556
19	Base Energy Charge Revenue	41,557	50,225	66,820	61,370	61,275	47,691	39,792	39,508	47,516	46,158	39,043	41,138	582,093
20	Total Present Base Rate Revenue	$99,379	$140,705	$171,081	$150,351	$160,443	$127,984	$100,012	$81,153	$111,930	$104,580	$97,465	$93,568	$1,438,650
21	FPPCA	33,061	39,958	53,160	48,824	48,749	37,942	31,658	31,431	37,802	36,722	31,061	32,728	463,094
22	Total Present Revenue	$132,440	$180,662	$224,241	$199,174	$209,192	$165,926	$131,670	$112,584	$149,731	$141,302	$128,526	$126,295	$1,901,744
23														
24	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
25	Fixed Demand Charge	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
33	Fixed Demand Charge Revenue	$28,361	$28,329	$28,429	$28,443	$28,518	$29,079	$28,910	$28,748	$28,746	$28,530	$28,493	$28,556	$343,141
34	O&M Demand Charge Revenue	49,173	49,116	49,290	49,315	49,444	50,417	50,124	49,843	49,840	49,465	49,401	49,510	594,938
35	Base Resource Energy Revenue	59,571	76,459	90,766	89,941	91,078	72,511	60,577	60,144	72,334	70,268	59,436	47,607	850,693
36	Other Existing Resources Energy Revenu	7,216	0	21,419	6,809	3,762	0	0	0	0	0	0	29,361	68,568
37	Additional ARM Resources	0	0	0	0	545	178	0	0	0	0	0	0	723
38	Total Proposed Base Rate Revenue	$144,322	$153,905	$189,905	$174,508	$173,346	$152,185	$139,611	$138,736	$150,920	$148,263	$137,329	$155,034	$1,858,063
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$144,322	$153,905	$189,905	$174,508	$173,346	$152,185	$139,611	$138,736	$150,920	$148,263	$137,329	$155,034	$1,858,063
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$19,711	($13,034)	($26,541)	($11,223)	($21,206)	($797)	$18,815	$36,947	$14,171	$19,574	$19,471	$25,636	$81,523
44	Change in Base Energy Charge Revenue	25,231	26,234	45,365	35,381	34,110	24,997	20,785	20,636	24,819	24,110	20,393	35,830	337,890
45	Change in Base Rate Revenue	$44,942	$13,200	$18,824	$24,158	$12,903	$24,201	$39,599	$57,583	$38,990	$43,683	$39,864	$61,466	$419,414
46	Change in FPPCA Revenue	(33,061)	(39,958)	(53,160)	(48,824)	(48,749)	(37,942)	(31,658)	(31,431)	(37,802)	(36,722)	(31,061)	(32,728)	(463,094)
47	Change in Total Revenue	$11,881	($26,758)	($34,336)	($24,666)	($35,845)	($13,741)	$7,942	$26,152	$1,188	$6,961	$8,803	$28,739	($43,680)
48	Percentage Change in Base Rate Reven	45.22%	9.38%	11.00%	16.07%	8.04%	18.91%	39.59%	70.96%	34.83%	41.77%	40.90%	65.69%	29.15%
49	Percentage Change in Total Revenue	8.97%	-14.81%	-15.31%	-12.38%	-17.14%	-8.28%	6.03%	23.23%	0.79%	4.93%	6.85%	22.75%	-2.30%

Arizona Electric Power Cooperative, Inc.

GRAHAM ADJUSTED PRESENT WITH SYCHRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	21,235	29,349	40,099	39,125	36,733	30,341	27,052	18,498	21,918	20,119	19,731	19,458	323,658
3	kW - Current Year	20,966	31,511	39,951	39,726	36,986	32,263	24,988	18,448	20,642	19,992	18,818	20,271	324,562
4	kW - 12 Month Average	26,949	27,129	27,117	27,167	27,188	27,348	27,176	27,172	27,066	27,055	26,979	27,047	325,394
5	ARM Load Ratio Share	67.93%	67.83%	67.68%	67.93%	68.05%	67.85%	67.61%	67.84%	67.83%	67.79%	67.84%	67.88%	67.84%
6	KWH - TOTAL	10,775,112	12,244,130	18,499,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
7	KWH - BASE RESOURCES	10,146,411	12,244,130	16,506,717	17,305,943	17,238,326	13,784,286	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	8,877,170	149,870,030
8	KWH - OTHER EXISTING RESOURCES	628,701	0	1,992,449	670,155	364,234	(0)	0	0	0	0	0	2,800,373	6,455,912
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	52,763	17,309	0	0	0	0	0	0	70,073
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$314,071	$472,035	$598,466	$595,095	$554,050	$483,300	$374,320	$276,351	$309,217	$299,480	$281,894	$303,660	$4,861,939
19	Base Energy Charge Revenue	223,368	253,821	383,488	372,645	365,995	286,107	229,621	214,235	248,760	230,816	191,158	242,075	3,242,089
20	Total Present Base Rate Revenue	$537,439	$725,856	$981,954	$967,740	$920,045	$769,407	$603,942	$490,586	$557,978	$530,296	$473,052	$545,735	$8,104,028
21	FPPCA	177,704	201,931	305,090	296,463	291,173	227,617	182,679	170,438	197,905	183,629	152,079	192,587	2,579,296
22	Total Present Revenue	$715,143	$927,787	$1,287,044	$1,264,203	$1,211,218	$997,024	$786,620	$661,025	$755,883	$713,925	$625,131	$738,322	$10,683,325
23														
24	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
25	Fixed Demand Charge	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	$238,793	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
33	Fixed Demand Charge Revenue	$162,216	$161,968	$161,617	$162,221	$162,488	$162,022	$161,438	$162,007	$161,977	$161,878	$162,003	$162,088	$1,943,922
34	O&M Demand Charge Revenue	281,251	280,820	280,211	281,259	281,721	280,914	279,902	280,887	280,835	280,663	280,882	281,028	3,370,373
35	Base Resource Energy Revenue	320,198	386,398	520,916	546,137	544,003	435,002	349,558	326,136	378,694	351,376	291,005	280,144	4,729,567
36	Other Existing Resources Energy Revenu	38,789	0	122,927	41,346	22,472	(0)	0	0	0	0	0	172,773	398,307
37	Additional ARM Resources	0	0	0	0	3,255	1,068	0	0	0	0	0	0	4,323
38	Total Proposed Base Rate Revenue	$802,454	$829,185	$1,085,670	$1,030,964	$1,013,939	$879,006	$790,898	$769,030	$821,506	$793,917	$733,890	$896,033	$10,446,493
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$802,454	$829,185	$1,085,670	$1,030,964	$1,013,939	$879,006	$790,898	$769,030	$821,506	$793,917	$733,890	$896,033	$10,446,493
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$129,396	($29,247)	($156,638)	($151,615)	($109,842)	($40,364)	$67,020	$166,543	$133,595	$143,061	$160,991	$139,456	$452,356
44	Change in Base Energy Charge Revenue	135,619	132,577	260,355	214,839	203,736	149,962	119,937	111,900	129,934	120,561	99,847	210,842	1,890,108
45	Change in Base Rate Revenue	$265,015	$103,329	$103,717	$63,224	$93,894	$109,599	$186,957	$278,443	$263,528	$263,621	$260,838	$350,298	$2,342,464
46	Change in FPPCA Revenue	(177,704)	(201,931)	(305,090)	(296,463)	(291,173)	(227,617)	(182,679)	(170,438)	(197,905)	(183,629)	(152,079)	(192,587)	(2,579,296)
47	Change in Total Revenue	$87,311	($98,602)	($201,373)	($233,240)	($197,279)	($118,018)	$4,278	$108,005	$65,623	$79,992	$108,759	$157,711	($236,832)
48	Percentage Change in Base Rate Revenu	49.31%	14.24%	10.56%	6.53%	10.21%	14.24%	30.96%	56.76%	47.23%	49.71%	55.14%	64.19%	28.90%
49	Percentage Change in Total Revenue	12.21%	-10.63%	-15.65%	-18.45%	-16.29%	-11.84%	0.54%	16.34%	8.68%	11.20%	17.40%	21.36%	-2.22%

Arizona Electric Power Cooperative, Inc.

MOHAVE ADJUSTED PRESENT WITH SYCHRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$855,113	$855,113	$855,113	$855,113	$855,113	$841,539	$855,113	$855,113	$855,113	$841,248	$855,113	$841,405	$10,220,208
7														
8	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
9	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
10	KWH - BASE RESOURCES	50,755,139	78,652,286	76,386,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
11	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,679,515
12	Demand Revenue	$1,814,798	$2,046,290	$2,167,510	$2,168,113	$2,167,010	$2,131,670	$1,926,246	$1,646,083	$1,719,895	$1,680,468	$1,698,967	$1,565,038	$22,732,087
13	Base Energy Charge Revenue	1,612,943	1,703,368	1,755,123	1,919,342	1,913,881	1,723,372	1,527,516	1,243,970	1,322,828	1,241,118	1,096,053	1,087,114	18,146,629
14	Total Present Base Rate Revenue	$3,427,741	$3,749,659	$3,922,633	$4,087,455	$4,080,891	$3,855,042	$3,453,762	$2,890,053	$3,042,723	$2,921,585	$2,795,020	$2,652,152	$40,878,716
15	FPPCA	1,184,537	1,250,945	1,288,953	1,409,555	1,405,545	1,265,635	1,121,800	913,565	971,478	911,470	804,936	798,371	13,326,790
16	Total Present Revenue	$4,612,278	$5,000,603	$5,211,586	$5,497,011	$5,486,436	$5,120,677	$4,575,562	$3,803,618	$4,014,201	$3,833,055	$3,599,956	$3,450,523	$54,205,506
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	
20	O&M Demand Charge	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	
21	Base Resource Energy Charge	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	
22	Other Existing Resources Energy Charge	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$727,283	$8,727,401
27	O&M Demand Charge Revenue	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	15,298,589
28	Base Resource Energy Revenue	1,631,645	2,528,466	2,455,622	2,594,195	2,612,518	2,472,658	2,217,326	1,887,770	2,008,670	1,871,542	1,673,996	1,271,666	25,226,075
29	Other Existing Resources Energy Revenue	1,860,829	241,921	569,519	817,930	760,603	427,710	324,157	88,450	91,425	113,708	55,049	886,267	6,237,567
30	Total Proposed Base Rate Revenue	$5,494,640	$4,772,552	$5,027,307	$5,414,290	$5,375,287	$4,902,534	$4,543,649	$3,978,386	$4,102,261	$3,987,416	$3,731,210	$4,160,099	$55,489,632
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$5,494,640	$4,772,552	$5,027,307	$5,414,290	$5,375,287	$4,902,534	$4,543,649	$3,978,386	$4,102,261	$3,987,416	$3,731,210	$4,160,099	$55,489,632
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$187,368	($44,124)	($165,345)	($165,947)	($164,844)	($129,504)	$75,920	$356,083	$282,271	$321,698	$303,199	$437,128	$1,293,903
36	Change in Energy Charge Revenue	1,879,531	1,067,018	1,270,019	1,492,782	1,459,239	1,176,997	1,013,968	732,250	777,267	744,133	632,991	1,070,819	13,317,014
37	Change in Base Rate Revenue	$2,066,899	$1,022,894	$1,104,674	$1,326,835	$1,294,396	$1,047,493	$1,089,887	$1,088,333	$1,059,538	$1,065,831	$936,190	$1,507,947	$14,610,916
38	Change in FPPCA Revenue	(1,184,537)	(1,250,945)	(1,288,953)	(1,409,555)	(1,405,545)	(1,265,635)	(1,121,800)	(913,565)	(971,478)	(911,470)	(804,936)	(798,371)	(13,326,790)
39	Change in Total Revenue	$882,362	($228,051)	($184,279)	($82,720)	($111,149)	($218,143)	($31,912)	$174,768	$88,060	$154,361	$131,255	$709,576	$1,284,127
40	Percentage Change in Base Rate Revenue	60.30%	27.28%	28.16%	32.46%	31.72%	27.17%	31.56%	37.66%	34.82%	36.48%	33.49%	56.86%	35.74%
41	Percentage Change in Total Revenue	19.13%	-4.56%	-3.54%	-1.50%	-2.03%	-4.26%	-0.70%	4.59%	2.19%	4.03%	3.65%	20.56%	2.37%

Arizona Electric Power Cooperative, Inc.

SULPHUR SPRINGS ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$9,089,148
7														
8	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
9	KW	131,134	137,934	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	138,700	128,900	1,629,806
10	KWH - BASE RESOURCES	45,109,060	71,215,789	67,765,404	69,476,926	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	38,298,091	738,282,902
11	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
12	Demand Revenue	$1,709,462	$1,758,830	$1,824,896	$1,771,898	$1,757,378	$1,744,310	$1,716,722	$1,616,534	$1,784,966	$1,778,911	$1,764,391	$1,693,243	$20,921,540
13	Base Energy Charge Revenue	1,446,096	1,558,774	1,553,892	1,562,858	1,569,492	1,501,590	1,434,581	1,287,408	1,460,597	1,440,640	1,326,890	1,416,282	17,559,098
14	Total Present Base Rate Revenue	$3,155,558	$3,317,604	$3,378,788	$3,334,756	$3,326,869	$3,245,900	$3,151,303	$2,903,941	$3,245,563	$3,219,551	$3,091,281	$3,109,525	$38,480,637
15	FPPCA	1,115,571	1,202,495	1,198,729	1,205,646	1,210,763	1,158,381	1,106,688	993,153	1,126,758	1,111,362	1,023,611	1,092,571	13,545,728
16	Total Present Revenue	$4,271,129	$4,520,099	$4,577,516	$4,540,401	$4,537,632	$4,404,281	$4,257,990	$3,897,095	$4,372,320	$4,330,913	$4,114,892	$4,202,096	$52,026,365
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	
20	O&M Demand Charge	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	
21	Base Resource Energy Charge	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	
22	Other Existing Resources Energy Charge	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$643,991	$7,727,894
27	O&M Demand Charge Revenue	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	13,546,516
28	Base Resource Energy Revenue	1,456,357	2,299,219	2,187,822	2,243,079	2,266,032	2,208,312	2,056,423	1,889,857	2,093,151	2,030,752	1,868,240	1,236,399	23,835,642
29	Other Existing Resources Energy Revenue	1,645,489	265,575	480,184	394,804	368,707	269,395	367,667	238,139	375,504	440,258	409,980	2,004,284	7,259,986
30	Total Proposed Base Rate Revenue	$4,874,713	$4,337,661	$4,440,874	$4,410,751	$4,407,607	$4,250,575	$4,196,957	$3,900,864	$4,241,522	$4,243,877	$4,051,087	$5,013,550	$52,370,038
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$4,874,713	$4,337,661	$4,440,874	$4,410,751	$4,407,607	$4,250,575	$4,196,957	$3,900,864	$4,241,522	$4,243,877	$4,051,087	$5,013,550	$52,370,038
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$63,406	$14,038	($52,028)	$970	$15,490	$28,558	$56,146	$156,334	($12,098)	($6,044)	$8,476	$79,624	$352,870
36	Change in Energy Charge Revenue	1,655,750	1,006,020	1,114,115	1,075,026	1,065,248	976,117	989,509	840,589	1,008,058	1,030,370	951,329	1,824,400	13,536,530
37	Change in Base Rate Revenue	$1,719,156	$1,020,057	$1,062,087	$1,075,995	$1,080,737	$1,004,675	$1,045,655	$996,923	$995,959	$1,024,326	$959,806	$1,904,025	$13,889,401
38	Change in FPPCA Revenue	(1,115,571)	(1,202,495)	(1,198,729)	(1,205,646)	(1,210,763)	(1,158,381)	(1,106,688)	(993,153)	(1,126,758)	(1,111,362)	(1,023,611)	(1,092,571)	(13,545,728)
39	Change in Total Revenue	$603,585	($182,438)	($136,642)	($129,650)	($130,026)	($153,706)	($61,033)	$3,769	($130,798)	($87,036)	($63,805)	$811,453	$343,673
40	Percentage Change in Base Rate Revenue	54.48%	30.75%	31.43%	32.27%	32.49%	30.95%	33.18%	34.33%	30.69%	31.82%	31.05%	61.23%	36.09%
41	Percentage Change in Total Revenue	14.13%	-4.04%	-2.99%	-2.86%	-2.87%	-3.49%	-1.43%	0.10%	-2.99%	-2.01%	-1.55%	19.31%	0.66%

Arizona Electric Power Cooperative, Inc.

TRICO ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	88,830	110,939	146,640	163,888	146,704	139,833	110,067	87,080	92,923	87,572	84,462	69,545	1,328,483
3	kW - Current Year	85,906	125,972	164,592	149,858	155,646	141,128	116,545	91,700	90,417	85,278	81,248	73,021	1,361,311
4	kW - 12 Month Moving Average	110,463	111,716	113,212	112,043	112,788	112,896	113,436	113,821	113,612	113,421	113,153	113,443	1,354,003
5	KWH - TOTAL	43,348,839	49,883,272	69,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
6	KWH - BASE RESOURCES	30,122,267	46,767,098	49,428,600	52,271,075	52,631,923	49,492,013	44,675,503	41,333,563	47,031,999	44,237,586	39,114,179	25,511,101	522,616,908
7	KWH - OTHER EXISTING RESOURCES	13,226,572	3,116,174	19,715,226	19,959,774	17,638,950	11,736,310	6,052,772	1,600,986	2,918,665	3,781,325	2,645,818	18,179,457	120,572,028
8	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,323,200	774,400	0	0	0	0	0	0	3,097,600
9														
10	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
11	Energy & FPPCA RATES													
12	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
13	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
14	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
15														
16	**PRESENT REVENUES**													
17	Demand Revenue	$1,286,872	$1,887,061	$2,465,588	$2,244,873	$2,331,577	$2,114,097	$1,745,844	$1,373,666	$1,354,447	$1,277,464	$1,217,095	$1,093,855	$20,392,439
18	Base Energy Charge Revenue	898,621	1,034,080	1,433,352	1,497,345	1,504,875	1,285,316	1,051,597	890,033	1,035,477	995,432	865,685	905,705	13,397,520
19	Total Present Base Rate Revenue	$2,185,493	$2,921,141	$3,898,940	$3,742,218	$3,836,452	$3,399,414	$2,797,441	$2,263,699	$2,389,924	$2,272,896	$2,082,780	$1,999,560	$33,789,959
20	FPPCA	714,913	822,679	1,140,326	1,191,237	1,197,228	1,022,554	836,615	708,080	823,791	791,932	688,709	720,548	10,658,613
21	Total Present Revenue	$2,900,406	$3,743,820	$5,039,266	$4,933,456	$5,033,680	$4,421,968	$3,634,056	$2,971,779	$3,213,715	$3,064,828	$2,771,489	$2,720,108	$44,448,572
22														
23	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
24	Fixed Demand Charge	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	
25	O&M Demand Charge	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	
26	Base Resource Energy Charge	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	
27	Other Existing Resources Energy Charge	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	
28	Additional ARM Resources	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	
29	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
30														
31	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
32	Fixed Demand Charge Revenue	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$646,435	$7,757,219
33	O&M Demand Charge Revenue	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	9,173,582
34	Base Resource Energy Revenue	975,449	1,514,458	1,600,645	1,692,693	1,704,378	1,602,698	1,446,726	1,338,504	1,523,036	1,432,544	1,266,633	826,125	16,923,888
35	Other Existing Resources Energy Revenue	873,507	205,798	1,302,030	1,318,181	1,164,909	775,088	399,736	105,732	192,754	249,726	174,735	1,200,605	7,962,802
36	Additional ARM Resources	0	0	0	0	153,428	51,143	0	0	0	0	0	0	204,571
37	Total Proposed Base Rate Revenue	$3,259,856	$3,131,156	$4,313,575	$4,421,774	$4,433,616	$3,839,829	$3,257,362	$2,855,136	$3,126,690	$3,093,170	$2,852,268	$3,437,631	$42,022,063
38	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
39	Total Proposed Revenue	$3,259,856	$3,131,156	$4,313,575	$4,421,774	$4,433,616	$3,839,829	$3,257,362	$2,855,136	$3,126,690	$3,093,170	$2,852,268	$3,437,631	$42,022,063
40														
41	**PROPOSED REVENUE CHANGES**													
42	Change in Fixed and Demand Revenue	$124,028	($476,160)	($1,054,688)	($833,973)	($920,677)	($703,197)	($334,944)	$37,234	$56,453	$133,436	$193,805	$317,046	($3,461,637)
43	Change in Base Energy Charge Revenue	950,335	686,175	1,469,324	1,513,528	1,517,841	1,143,613	794,865	554,202	680,313	686,838	575,683	1,121,025	11,693,741
44	Change in Base Rate Revenue	$1,074,363	$210,015	$414,636	$679,555	$597,164	$440,415	$459,921	$591,437	$736,766	$820,274	$769,488	$1,438,071	$8,232,104
45	Change in FPPCA Revenue	(714,913)	(822,679)	(1,140,326)	(1,191,237)	(1,197,228)	(1,022,554)	(836,615)	(708,080)	(823,791)	(791,932)	(688,709)	(720,548)	(10,658,613)
46	Change in Total Revenue	$359,450	($612,664)	($725,690)	($511,682)	($600,064)	($582,139)	($376,694)	($116,644)	($87,024)	$28,342	$80,779	$717,522	($2,426,509)
47	Percentage Change in Base Rate Revenue	49.16%	7.19%	10.63%	18.16%	15.57%	12.96%	16.44%	26.13%	30.83%	36.09%	36.95%	71.92%	24.36%
48	Percentage Change in Total Revenue	12.39%	-16.36%	-14.40%	-10.37%	-11.92%	-13.16%	-10.37%	-3.93%	-2.71%	0.92%	2.91%	26.38%	-5.46%

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED PRESENT WITH SYNCHRONIZED FPPCA AND PROPOSED REVENUES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	PRESENT REVENUES w/ FPPAC SYNCHRONIZED													
2	FULL REQUIREMENTS													
3	Demand Revenue	$457,459	$674,684	$861,635	$839,929	$802,239	$708,659	$537,183	$398,708	$506,354	$479,135	$446,239	$450,524	$7,162,747
4	Base Energy Revenue	342,330	386,433	544,585	543,186	532,724	423,140	349,464	330,090	393,351	362,518	312,364	367,112	4,887,288
5	Total Present Base Rate Revenue	$799,789	$1,061,117	$1,406,220	$1,383,115	$1,334,963	$1,131,799	$886,647	$728,797	$899,705	$841,653	$758,594	$817,635	$12,050,035
6	FPPCA	272,346	307,433	433,253	432,140	423,818	336,636	278,022	262,608	312,936	288,407	248,498	292,062	3,888,161
7	Total Adjusted Present Revenue	$1,072,135	$1,368,550	$1,839,473	$1,815,255	$1,758,781	$1,468,435	$1,164,669	$991,406	$1,212,641	$1,130,061	$1,007,092	$1,109,697	$15,938,195
8														
9	PARTIAL REQUIREMENTS													
10	Fixed / O&M Charge Revenue	$4,811,132	$5,692,181	$6,457,994	$6,184,884	$6,255,964	$5,990,077	$5,388,812	$4,636,283	$4,859,308	$4,736,843	$4,680,453	$4,352,135	$64,046,066
11	Base Energy Revenue	3,957,660	4,296,223	4,742,366	4,879,546	4,988,248	4,510,278	4,013,694	3,421,411	3,818,902	3,677,189	3,288,628	3,409,102	49,103,246
12	Total Present Base Rate Revenue	$8,768,792	$9,988,403	$11,200,360	$11,164,430	$11,244,213	$10,500,356	$9,402,506	$8,057,693	$8,678,209	$8,414,032	$7,969,081	$7,761,237	$113,149,312
13	FPPCA	3,015,021	3,276,119	3,628,008	3,806,438	3,813,535	3,446,571	3,065,103	2,614,799	2,922,026	2,814,764	2,517,256	2,611,491	37,531,131
14	Total Adjusted Present Revenue	$11,783,813	$13,264,523	$14,828,368	$14,970,868	$15,057,748	$13,946,926	$12,467,608	$10,672,492	$11,600,236	$11,228,797	$10,486,337	$10,372,728	$150,680,443
15														
16	TOTAL CLASS A													
17	Demand Revenue	$5,268,591	$6,366,865	$7,319,629	$7,024,812	$7,058,203	$6,698,736	$5,925,995	$5,034,990	$5,365,662	$5,215,978	$5,126,692	$4,802,659	$71,208,813
18	Base Energy Revenue	4,299,990	4,682,656	5,286,951	5,522,732	5,520,973	4,933,419	4,363,158	3,751,501	4,212,252	4,039,707	3,600,982	3,776,213	53,990,534
19	Total Present Base Rate Revenue	$9,568,581	$11,049,521	$12,606,580	$12,547,544	$12,579,176	$11,632,155	$10,289,153	$8,786,491	$9,577,914	$9,255,686	$8,727,674	$8,578,872	$125,199,347
20	FPPCA	3,287,367	3,583,552	4,061,261	4,238,578	4,237,353	3,783,207	3,343,125	2,877,407	3,234,962	3,103,171	2,765,755	2,903,553	41,419,292
21	Total Adjusted Present Revenue	$12,855,948	$14,633,073	$16,667,841	$16,786,123	$16,816,529	$15,415,362	$13,632,278	$11,663,898	$12,812,877	$12,358,857	$11,493,429	$11,482,425	$166,618,638
22														
23	PROPOSED REVENUES													
24	FULL REQUIREMENTS													
25	Demand Revenue	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$652,811	$7,833,734
26	Base Energy Revenue	550,177	588,277	914,311	856,347	829,273	644,929	531,998	502,504	598,807	551,870	475,505	686,857	7,730,854
27	Total Proposed Base Rate Revenue	$1,202,988	$1,241,088	$1,567,122	$1,509,158	$1,482,084	$1,297,740	$1,184,810	$1,155,315	$1,251,618	$1,204,681	$1,128,316	$1,339,668	$15,564,588
28	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total Adjusted Proposed Revenue	$1,202,988	$1,241,088	$1,567,122	$1,509,158	$1,482,084	$1,297,740	$1,184,810	$1,155,315	$1,251,618	$1,204,681	$1,128,316	$1,339,668	$15,564,588
30														
31	PARTIAL REQUIREMENTS													
32	Fixed / O&M Charge Revenue	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$5,185,933	$62,231,201
33	Base Energy Revenue	8,443,276	7,055,436	8,595,823	9,060,881	9,030,576	7,807,005	6,812,035	5,548,452	6,284,539	6,138,530	5,448,632	7,425,346	87,650,532
34	Total Proposed Base Rate Revenue	$13,629,209	$12,241,369	$13,781,757	$14,246,815	$14,216,509	$12,992,938	$11,997,969	$10,734,386	$11,470,473	$11,324,464	$10,634,565	$12,611,280	$149,881,733
35	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total Adjusted Proposed Revenue	$13,629,209	$12,241,369	$13,781,757	$14,246,815	$14,216,509	$12,992,938	$11,997,969	$10,734,386	$11,470,473	$11,324,464	$10,634,565	$12,611,280	$149,881,733
37														
38	TOTAL CLASS A													
39	Demand Revenue	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$5,838,745	$70,064,935
40	Base Energy Revenue	8,993,452	7,643,712	9,510,135	9,917,228	9,859,848	8,451,934	7,344,034	6,050,956	6,883,347	6,690,400	5,924,137	8,112,203	95,381,386
41	Total Proposed Base Rate Revenue	$14,832,197	$13,482,457	$15,348,879	$15,755,973	$15,698,593	$14,290,678	$13,182,778	$11,889,701	$12,722,091	$12,529,145	$11,762,881	$13,950,948	$165,446,321
42	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Adjusted Proposed Revenue	$14,832,197	$13,482,457	$15,348,879	$15,755,973	$15,698,593	$14,290,678	$13,182,778	$11,889,701	$12,722,091	$12,529,145	$11,762,881	$13,950,948	$165,446,321
44														
45	PROPOSED REVENUE CHANGES													
46	FULL REQUIREMENTS													
47	Demand Revenue	$195,352	($21,873)	($208,823)	($187,117)	($149,428)	($55,848)	$115,628	$254,103	$146,457	$173,676	$206,572	$202,288	$670,987
48	Base Energy Revenue	207,847	201,844	369,726	313,161	296,548	221,788	182,534	172,414	205,457	189,352	163,150	319,745	2,843,566
49	Change in Base Rate Revenue	$403,199	$179,971	$160,903	$126,043	$147,120	$165,941	$298,162	$426,518	$351,914	$363,028	$369,722	$522,033	$3,514,553
50	FPPCA	(272,346)	(307,433)	(433,253)	(432,140)	(423,818)	(336,636)	(278,022)	(262,608)	(312,936)	(288,407)	(248,498)	(292,062)	(3,888,161)
51	Total Revenue Change	$130,853	($127,463)	($272,351)	($306,097)	($276,697)	($170,696)	$20,140	$163,909	$38,978	$74,621	$121,224	$229,971	($373,607)
52	Percent Change in Base Rate Revenue	4.60%	1.80%	1.44%	1.13%	1.31%	1.58%	3.17%	5.29%	4.06%	4.31%	4.64%	6.73%	3.11%
53	Percent Change in Total Revenue	12.20%	-9.31%	-14.81%	-16.86%	-15.73%	-11.62%	1.73%	16.53%	3.21%	6.60%	12.04%	20.72%	-2.34%
54														
55	PARTIAL REQUIREMENTS													
56	Fixed / O&M Charge Revenue	$374,802	($506,247)	($1,272,061)	($998,950)	($1,070,031)	($804,144)	($202,879)	$549,651	$326,626	$449,090	$505,481	$833,798	($1,814,864)
57	Base Energy Revenue	4,485,615	2,759,213	3,853,458	4,081,336	4,042,327	3,296,726	2,798,342	2,127,042	2,465,637	2,461,341	2,160,004	4,016,245	38,547,286
58	Change in Base Rate Revenue	$4,860,417	$2,252,966	$2,581,397	$3,082,385	$2,972,296	$2,492,583	$2,595,463	$2,676,692	$2,792,263	$2,910,431	$2,665,485	$4,850,043	$36,732,421
59	FPPCA	(3,015,021)	(3,276,119)	(3,628,008)	(3,806,438)	(3,813,535)	(3,446,571)	(3,065,103)	(2,614,799)	(2,922,026)	(2,814,764)	(2,517,256)	(2,611,491)	(37,531,131)
60	Total Revenue Change	$1,845,396	($1,023,153)	($1,046,611)	($724,053)	($841,239)	($953,988)	($469,640)	$61,894	($129,763)	$95,667	$148,228	$2,238,551	($798,710)
61	Percent Change in Base Rate Revenue	55.43%	22.56%	23.05%	27.61%	26.43%	23.74%	27.60%	33.22%	32.18%	34.59%	33.45%	62.49%	32.46%
62	Percent Change in Total Revenue	15.66%	-7.71%	-7.06%	-4.84%	-5.59%	-6.84%	-3.77%	0.58%	-1.12%	0.85%	1.41%	21.58%	-0.53%
63														
64	TOTAL CLASS A													
65	Demand Revenue	$570,154	($528,120)	($1,480,884)	($1,186,068)	($1,219,459)	($859,991)	($87,250)	$803,754	$473,083	$622,766	$712,053	$1,036,086	($1,143,877)
66	Base Energy Revenue	4,693,462	2,961,057	4,223,184	4,394,496	4,338,876	3,518,515	2,980,875	2,299,456	2,671,094	2,650,693	2,323,154	4,335,990	41,390,852
67	Percent Change in Base Rate Revenue	$5,263,616	$2,432,936	$2,742,299	$3,208,429	$3,119,417	$2,658,523	$2,893,625	$3,103,210	$3,144,177	$3,273,459	$3,035,207	$5,372,076	$40,246,975
68	FPPCA	(3,287,367)	(3,583,552)	(4,061,261)	(4,238,578)	(4,237,353)	(3,783,207)	(3,343,125)	(2,877,407)	(3,234,962)	(3,103,171)	(2,765,755)	(2,903,553)	(41,419,292)
69	Total Revenue Change	$1,976,249	($1,150,616)	($1,318,962)	($1,030,150)	($1,117,936)	($1,124,684)	($449,499)	$225,803	($90,785)	$170,288	$269,452	$2,468,523	($1,172,317)
70	Percent Change in Base Rate Revenue	55.01%	22.02%	21.75%	25.57%	24.80%	22.85%	28.12%	35.32%	32.83%	35.37%	34.78%	62.62%	32.15%
71	Percent Change in Total Revenue	15.37%	-7.86%	-7.91%	-6.14%	-6.65%	-7.30%	-3.30%	1.94%	-0.71%	1.38%	2.34%	21.50%	-0.70%

Arizona Electric Power Cooperative, Inc.

ANALYSIS OF REVENUE BY DETAILED CLASS WITH SYNCHRONIZED FPPCA

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**AVERAGE COST PER KWH - PRESENT REVENUES**													
2	ANZA	$0.06014	$0.06545	$0.07216	$0.06682	$0.06652	$0.07088	$0.06380	$0.05914	$0.06556	$0.06660	$0.06395	$0.06056	$0.06538
3	DUNCAN	$0.06607	$0.07457	$0.06957	$0.06728	$0.07077	$0.07212	$0.06859	$0.05907	$0.06532	$0.06346	$0.06824	$0.06364	$0.06773
4	GRAHAM	$0.06637	$0.07577	$0.06957	$0.07033	$0.06860	$0.07224	$0.07102	$0.06396	$0.06299	$0.06412	$0.06779	$0.06323	$0.06831
5	MOHAVE	$0.05928	$0.06086	$0.06155	$0.05937	$0.05943	$0.06160	$0.06210	$0.06338	$0.06291	$0.06402	$0.06809	$0.06580	$0.06192
6	SULPHER	$0.06123	$0.06011	$0.06107	$0.06022	$0.05993	$0.06080	$0.06153	$0.06275	$0.06206	$0.06232	$0.06429	$0.06151	$0.06142
7	TRICO	$0.06691	$0.07505	$0.07288	$0.06830	$0.06934	$0.07132	$0.07164	$0.06922	$0.06434	$0.06383	$0.06637	$0.06226	$0.06878
8	AEPCO CLASS A	$0.06198	$0.06478	$0.06535	$0.06301	$0.06314	$0.06477	$0.06477	$0.06445	$0.06306	$0.06342	$0.06616	$0.06303	$0.06397
9														
10	**AVERAGE COST PER KWH - PROPOSED REVENUES**													
11	ANZA	$0.06862	$0.06492	$0.06411	$0.05766	$0.05795	$0.06185	$0.06585	$0.06722	$0.05962	$0.06361	$0.06487	$0.07131	$0.06357
12	DUNCAN	$0.07199	$0.06352	$0.05892	$0.05895	$0.05864	$0.06615	$0.07273	$0.07279	$0.06584	$0.06659	$0.07292	$0.07812	$0.06617
13	GRAHAM	$0.07447	$0.06772	$0.05869	$0.05735	$0.05743	$0.06369	$0.07140	$0.07441	$0.06846	$0.07130	$0.07959	$0.07673	$0.06680
14	MOHAVE	$0.07062	$0.05808	$0.05938	$0.05848	$0.05822	$0.05897	$0.06166	$0.06630	$0.06429	$0.06660	$0.07057	$0.07933	$0.06339
15	SULPHER	$0.06988	$0.05769	$0.05924	$0.05850	$0.05822	$0.05868	$0.06065	$0.06281	$0.06020	$0.06107	$0.06329	$0.07338	$0.06183
16	TRICO	$0.07520	$0.06277	$0.06239	$0.06122	$0.06107	$0.06193	$0.06421	$0.06650	$0.06260	$0.06442	$0.06830	$0.07868	$0.06502
17	AEPCO CLASS A	$0.07151	$0.05969	$0.06018	$0.05914	$0.05894	$0.06005	$0.06263	$0.06570	$0.06261	$0.06429	$0.06772	$0.07659	$0.06352

Arizona Electric Power Cooperative, Inc.

CHANGES IN REPRESENTATIVE RATE SCHEDULES

Line No.	RATE DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TRICO ELECTRIC COOPERATIVE	COLLECTIVE ALL REQIREMENTS MEMBERS
1	PRESENT MONTHLY CHARGES					
2	FIXED CHARGE	$855,113	$757,429	$14.980	$14.980	$14.980
3	O&M CHARGE	$7.260	$7.260	N/A	N/A	N/A
4	TOTAL FIXED CHARGE PLUS O&M CHARGE	$1,894,341	$1,743,462	$14.980	$14.980	$14.980
5	BASE ENERGY CHARGE	N/A	N/A	N/A	N/A	N/A
6	OTHER EXISTING RESOURCE ENERGY CHARGE	N/A	N/A	N/A	N/A	N/A
7	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	N/A	N/A	N/A
8	AVERAGE ENERGY CHARGE	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730
9						
10	PROPOSED MONTHLY CHARGES					
11	FIXED CHARGE	$727,283	$643,991	$885,227	$646,435	$238,793
12	O&M CHARGE	$1,274,882	$1,128,876	$1,178,484	$764,465	$414,019
13	TOTAL FIXED CHARGE PLUS O&M CHARGE	$2,002,166	$1,772,867	$2,063,711	$1,410,900	$652,811
14	BASE ENERGY CHARGE	$0.032147	$0.032285	$0.032345	$0.032383	$0.031558
15	OTHER EXISTING RESOURCE ENERGY CHARGE	$0.068787	$0.066755	$0.067461	$0.066042	$0.061697
16	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	$0.067461	$0.066042	$0.061697
17	AVERAGE ENERGY CHARGE	$0.035943	$0.036711	$0.037211	$0.038824	$0.032791
18						
19	CHANGE IN MONTHLY CHARGES					
20	FIXED CHARGE	($127,830)	($113,438)	N/A	N/A	N/A
21	O&M CHARGE	$235,655	$142,844	N/A	N/A	N/A
22	TOTAL FIXED CHARGE PLUS O&M CHARGE	$107,825	$29,406	N/A	N/A	N/A
23	BASE ENERGY CHARGE	N/A	N/A	N/A	N/A	N/A
24	OTHER EXISTING RESOURCE ENERGY CHARGE	N/A	N/A	N/A	N/A	N/A
25	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	N/A	N/A	N/A
26	AVERAGE ENERGY CHARGE	$0.015213	$0.015981	$0.016481	$0.018094	$0.012061

Arizona Electric Power Cooperative, Inc.

TYPICAL BILL ANALYSIS

THIS SCHEDULE IS NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

BILL COUNT

THIS SCHEDULE IS NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

SUMMARY OF RESOURCE ENERGY COSTS AND BASE FUEL FACTORS

LINE NO.	DESCRIPTION	TOTAL	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS	TRICO	CARM
1	Base Resources						
2	Recoverable Fuel Costs	$76,156,589	$26,127,948	$24,634,228	$25,394,412	$17,435,429	$7,600,644
3	kWh Sales	2,282,789,101	784,700,545	738,282,902	759,805,654	522,616,908	226,109,971
4	Base Rate Fuel Factor	$0.033361	$0.033297	$0.033367	$0.033422	$0.033362	$0.033615
5							
6	Other Existing Resources						
7	Recoverable Fuel Costs	$22,648,067	$6,321,080	$7,875,240	$8,451,748	$8,560,516	$677,816
8	kWh Sales	318,474,678	90,679,515	108,755,098	119,040,065	120,572,028	9,546,812
9	Base Rate Fuel Factor	$0.071114	$0.069708	$0.072413	$0.070999	$0.070999	$0.070999
10							
11	Additional ARM Resources						
12	Recoverable Fuel Costs	$2,762,238	$0	$0	$2,762,238	$2,673,846	$88,392
13	kWh Sales	3,200,000	0	0	3,200,000	3,097,600	102,400
14	Base Rate Fuel Factor	$0.863199	$0.000000	$0.000000	$0.863199	$0.863199	$0.863199
15							
16	OER and Add ARM Resources Combined						
17	Recoverable Fuel Costs	$25,410,305	$6,321,080	$7,875,240	$11,213,985	$11,234,362	$766,208
18	kWh Sales	321,674,678	90,679,515	108,755,098	122,240,065	123,669,628	9,649,212
19	Base Rate Fuel Factor	$0.078994	$0.069708	$0.072413	$0.091737	$0.090842	$0.079406
20							
21	Total Resources						
22	Recoverable Fuel Costs	$101,566,893	$32,449,028	$32,509,468	$36,608,397	$28,669,790	$8,366,851
23	kWh Sales	2,604,463,779	875,380,060	847,038,000	882,045,719	646,286,536	235,759,183
24	Base Rate Fuel Factor	$0.038997	$0.037069	$0.038380	$0.041504	$0.044361	$0.035489

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

RESOURCE ENERGY COSTS AND CREDITS - ALL RESOURCES

LINE NO.	DESCRIPTION	TOTAL	BASE RESOURCES	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	Resource Costs for Member Use	$67,068,435	$56,603,695	$10,464,740	$0
2	Plus:				
3	Resource Costs for Tariff Load	$19,329,841	$19,329,841	$0	$0
4	Resource Costs for Resource Transfers	2,844,341	1,145,169	1,699,172	0
5	Resource Costs of Third Party Sales	2,507,121	2,507,121	0	0
6	Resource Transfer Credits	(1,699,172)	(1,699,172)	0	0
7	Subtotal	$22,982,131	$21,282,959	$1,699,172	$0
8					
9	Total Resource Costs - Fuel Expense Accounts 501 and 547	$90,050,566	$77,886,654	$12,163,912	$0
10					
11	Plus:				
12	Purchased Power Account 555 - Demand	$4,066,417	$1,701,090	$0	$2,365,328
13	Purchased Power Account 555 - Energy	10,779,792	751,678	9,793,204	234,910
14	Subtotal	$14,846,209	$2,452,768	$9,793,204	$2,600,238
15					
16	Plus:				
17	Non-Firm Transmission of Electricity by Others Account 565	$2,880	$2,880	$0	$0
18	Firm Transmission of Electricity by Others Account 565	4,499,040	3,198,060	1,138,980	162,000
19	Subtotal	$4,501,921	$3,200,940	$1,138,980	$162,000
20					
21	Less:				
22	Firm Contract Revenues (Energy-Related)	($2,448,992)	($2,448,992)	$0	$0
23	Resource Economy Energy	(3,952,272)	(3,504,243)	(448,029)	0
24	Firm Contract Revenues (Demand-Related)	(1,430,539)	(1,430,539)	0	0
25	Scheduling Revenues	0	0	0	0
26	Subtotal	($7,831,803)	($7,383,774)	($448,029)	$0
27					
28	Recoverable Resource Fuel Costs for FPPCA	$101,566,893	$76,156,589	$22,648,067	$2,762,238
29	Recoverable Resource Fuel Costs per kWh	$0.038997	$0.033361	$0.071114	$0.863199
30					
31	kWh Purchased by Class A Member by Resource Type	2,604,463,779	2,282,789,101	318,474,678	3,200,000

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

DEVELOPMENT OF BASE RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	BASE RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS	TRICO	CARM
1	Base Coal Costs for Member Use	$56,603,695	$19,457,317	$18,306,352	$18,840,027	$12,958,730	$5,606,589
2	Plus:						
3	Coal Costs for Tariff Load	$19,329,841	$6,678,640	$6,187,018	$6,464,183	$4,446,257	$1,923,671
4	Coal Costs for Resource Transfers	1,145,169	398,862	269,962	476,345	327,644	141,755
5	Coal Costs of Third Party Sales	2,507,121	1,199,603	705,665	601,853	413,972	179,105
6	Resource Transfer Credits	(1,699,172)	(572,118)	(405,130)	(721,924)	(496,561)	(214,837)
7	Subtotal	$21,282,959	$7,704,987	$6,757,515	$6,820,457	$4,691,313	$2,029,694
8							
9		$77,886,654	$27,162,304	$25,063,867	$25,660,484	$17,650,043	$7,636,283
10	Plus:						
11	Purchased Power Account 555 - Energy	$1,701,090	$584,744	$550,154	$566,192	$389,444	$168,493
12	Purchased Power Account 555 - Demand	751,678	269,101	238,282	244,295	158,604	85,691
13	Subtotal	$2,452,768	$853,844	$788,436	$810,488	$548,048	$254,184
14							
15	Plus:						
16	Non-Firm Transmission of Electricity by Others Account 565	2,880	990	932	959	659	285
17	Firm Transmission of Electricity by Others Account 565	3,198,060	1,144,905	1,013,785	1,039,369	674,791	364,579
18	Subtotal	$3,200,940	$1,145,896	$1,014,717	$1,040,328	$675,450	$364,864
19							
20	Total Fuel, Purchased Power and Wheeling Costs	$83,540,362	$29,162,043	$26,867,019	$27,511,300	$18,873,541	$8,255,331
21							
22	Less:						
23	Firm Contract Revenues (Energy-Related)	($2,448,992)	($841,832)	($792,035)	($815,125)	($560,667)	($242,572)
24	Base Resource Economy Energy	(3,504,243)	(1,680,130)	(987,275)	(836,838)	(575,602)	(249,034)
25	Firm Contract Revenues (Demand-Related	(1,430,539)	(512,133)	(453,481)	(464,925)	(301,844)	(163,081)
26	Subtotal	($7,383,774)	($3,034,095)	($2,232,791)	($2,116,888)	($1,438,113)	($654,688)
27							
28	Base Resource Recoverable Fuel Costs for FPPCA	$76,156,589	$26,127,948	$24,634,228	$25,394,412	$17,435,429	$7,600,644
29	Base Resource Recoverable Fuel Costs per kWh	$0.033361	$0.033297	$0.033367	$0.033422	$0.033362	$0.033615
30							
31	Base kWh Purchased by Class A Member	2,282,789,101	784,700,545	738,282,902	759,805,654	522,616,908	226,109,971
32	ACP Ratio	100.00%	35.80%	31.70%	32.50%	21.10%	11.40%

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

DEVELOPMENT OF OTHER EXISTING RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	OTHER EXISTING RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS	TRICO	CARM
1	Fuel Expense Account 547	$10,464,740	$2,979,633	$3,573,577	$3,911,530	$3,961,869	$313,698
2	Plus:						
3	Purchased Power Account 555 - Demand	0	0	0	0	0	0
4	Purchased Power Account 555 - Energy	9,793,204	2,788,426	3,344,256	3,660,522	3,707,630	293,568
5	Subtotal	$9,793,204	$2,788,426	$3,344,256	$3,660,522	$3,707,630	$293,568
6							
7	Plus:						
8	Other Existing Resource Costs for Resource Transfers	$1,699,172	$272,834	$749,346	$676,992	$685,704	$54,294
9							
10	Plus:						
11	Non-Firm Transmission of Electricity by Others Account 565	$0	$0	$0	$0	$0	$0
12	Firm Transmission of Electricity by Others Account 565	1,138,980	407,755	361,057	370,169	374,932	29,687
13	Subtotal	$1,138,980	$407,755	$361,057	$370,169	$374,932	$29,687
14							
15	Total Fuel, Purchased Power and Wheeling Costs	$23,096,096	$6,448,647	$8,028,236	$8,619,213	$8,730,136	$691,246
16							
17	Less:						
18	Firm Contract Revenues (Energy-Related)	$0	$0	$0	$0	$0	$0
19	OER Economy Energy	(448,029)	(127,568)	(152,996)	(167,465)	(169,620)	(13,430)
20	Subtotal	($448,029)	($127,568)	($152,996)	($167,465)	($169,620)	($13,430)
21							
22	Other Existing Resource Recoverable Fuel Costs for FPPCA	$22,648,067	$6,321,080	$7,875,240	$8,451,748	$8,560,516	$677,816
23	Other Existing Resource Recoverable Fuel Costs per kWh	$0.071114	$0.069708	$0.072413	$0.070999	$0.070999	$0.070999
24							
25	Other Resource kWh Purchased by Class A Member	318,474,678	90,679,515	108,755,098	119,040,065	120,572,028	9,546,812

Arizona Electric Power Cooperative, Inc.

DEVELOPMENT OF PPFCA BASES BY RESOURCE AND MEMBER

DEVELOPMENT OF ADDITIONAL ARM RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	ADDITIONAL ARM RESOURCES	MOHAVE EC	SULPHUR SPRINGS VALLEY EC	ALL REQUIREMENTS MEMBERS	TRICO	CARM
1	Purchased Power Account 555 - Demand	$2,365,328	$0	$0	$2,365,328	$2,289,637	$75,690
2	Purchased Power Account 555 - Energy	234,910	0	0	234,910	227,393	7,517
3	Subtotal	$2,600,238	$0	$0	$2,600,238	$2,517,030	$83,208
4							
5	Plus:						
6	Non-Firm Transmission of Electricity by Others Account 565	$0	$0	$0	$0	$0	$0
7	Firm Transmission of Electricity by Others Account 565	162,000	0	0	162,000	156,816	5,184
8	Subtotal	$162,000	$0	$0	$162,000	$156,816	$5,184
9							
10	Total Fuel, Purchased Power and Wheeling Costs	$2,762,238	$0	$0	$2,762,238	$2,673,846	$88,392
11							
12	Less:						
13	Firm Contract Revenues (Energy-Related)	$0	$0	$0	$0	$0	$0
14	Additional ARM Economy Energy	0	0	0	0	0	0
15	Scheduling Revenues	0	0	0	0	0	0
16	Subtotal	$0	$0	$0	$0	$0	$0
17							
18	Additional ARM Resource Recoverable Fuel Costs for FPPCA	$2,762,238	$0	$0	$2,762,238	$2,673,846	$88,392
19	Additional Resource Recoverable Fuel Costs per kWh	$0.863199	$0.000000	$0.000000	$0.863199	$0.863199	$0.863199
20							
21	Additional ARM kWh Purchased by Class A Member	3,200,000	0	0	3,200,000	3,097,600	102,400

Stipulation Among the Parties to the Arizona Electric Power Cooperative, Inc. Rate Case
Docket No. E-01773A-09-0472 ("AEPCO Rate Case")

The Arizona Electric Power Cooperative, Inc. ("AEPCO"), the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission") and the AEPCO Member Intervenors consisting of Mohave Electric Cooperative, Inc.("MEC"), Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") and Trico Electric Cooperative, Inc. ("Trico") (collectively, the "Member Intervenors") stipulate and agree that they will jointly recommend the following to the Administrative Law Judge and the Commission to resolve these issues in the currently pending AEPCO Rate Case.

1. Revenue Requirements. With reference to Column 5 of Exhibit GEP-4 (Pierson Rejoinder Testimony), the Parties recommend that the Commission approve Operating Revenues of $177,590,362 based upon a Debt Service Coverage Ratio of 1.32, which is a revenue decrease of $1,172,317 over revenues in the test year at present rates. Those revenues produce $14,770,063 in electric operating margins for a 6.97% return on the Fair Value Rate base of $211,802,594, which the Parties agree is a just and reasonable return.

2. Recommended Rates. As set forth in Column 6 of Exhibit GEP-5 (Pierson Rejoinder Testimony), the Parties recommend that the Commission approve the rates and the Purchased Power Fuel Adjustor Clause ("PPFAC") bases stated in that column. In that regard, AEPCO will present testimony at hearing that those rates and PPFAC bases are consistent with the provisions and requirements of the Contract and Contract Amendments which were filed for Commission approval in this Docket by AEPCO and the Member Intervenors on June 2, 2010.

3. Contract and Contract Amendment Approvals. Subject to the prior approval of the Rural Utilities Service ("RUS"), the Parties recommend that the Commission approve the Contract and the Contract Amendments which were filed in this Docket on June 2, 2010, i.e., the Partial-Requirements Capacity and Energy Agreement between AEPCO and Trico; the Third Amendment to the MEC Partial; the First Amendment to the SSVEC Partial; the Ninth Amendment to the Wholesale Power Contract between AEPCO and Duncan Valley Electric Cooperative, Inc.; and the Seventh Amendment to the Wholesale Power Contract between AEPCO and GCEC. AEPCO will promptly file in this Docket notice of RUS approval of the Contract and Contract Amendments once received.

4. Rates Effective Date. Following receipt of RUS approval of the Contract and Contract Amendments, the Parties recommend the Rates take effect on the first day of the month following the effective date of Commission approval of the final rate decision.

5. PPFAC Issues. The Parties recommend that the Commission approve the temporary surcharge mechanism to close out existing clause balances as described at page 11 of AEPCO witness Pierson's rejoinder testimony. Further, the Parties recommend that the Commission continue in effect the "efficacy" provision in relation to the PPFAC as described at page 12 of Mr. Pierson's rejoinder testimony.

EXHIBIT
A-9
ADMITTED

6. Action Plan. The Parties agree that AEPCO should file an action plan on Liberty Consulting's recommendations by February 1, 2011 with the reporting and confidentiality provisions set forth at pages 2-4 of Mr. Pierson's rejoinder testimony.

7. Procedural Recommendations. The Parties stipulate that all testimonies filed by the Parties in this matter may be received into evidence without objection and the Parties agree to waive cross-examination of the witnesses in relation to their filed testimonies. At the October 25, 2010 hearing on the AEPCO Rate Case, AEPCO and the Staff will provide a witness in support of this stipulation and to answer any questions in relation to it.

Arizona Electric Power Cooperative, Inc.

Comparison of Increase in Gross Revenue Requirement

Test Year Ended March 31, 2009

Line No.	Description	Col. 1 Company As Amended Position	Col. 2 Staff Direct Position	Col. 3 Company Rebuttal Position	Col. 4 Staff Surrebuttal Position	Col. 5 Company Rejoinder Position
1	Summary of Revenue Increase Proposed:					
2	Proposed Revenue Increase	$ (96,754)	$ 231,014	$ (1,172,317)	$ 231,014	$ (1,172,317)
3	Revenues in Test Year - Present Rates	$ 166,618,639	$ 166,618,639	$ 166,618,639	$ 166,618,639	$ 166,618,639
3	Revenue Increase Percentage	-0.06%	0.14% (1)	-0.70%	0.14%	-0.70%
4						
5	Pro Forma Statement of Operations					
6	with Proposed Rates:					
7	Operating Revenues	$ 178,665,925	$ 178,993,693	$ 177,590,362	$ 178,993,693	$ 177,590,362
8	Operating Expense	164,623,661	162,820,299	162,820,299	162,820,299	162,820,299
9	Electric Operating Margins	14,042,264	16,173,394	14,770,063	16,173,394	14,770,063
10	Interest & Other Deductions	11,917,826	11,822,642	11,822,642	11,822,642	11,822,642
11	Operating Margins	2,124,438	4,350,752	2,947,421	4,350,752	2,947,421
12	Non-Operating Margins	1,112,155	1,112,155	1,112,155	1,112,155	1,112,155
13	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576	$ 5,462,907	$ 4,059,576
14						
15	Times Interest Earned Ratio:					
16	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576	$ 5,462,907	$ 4,059,576
17	Interest on Long Term Debt	10,812,194	10,812,194	10,812,194	10,812,194	10,812,194
18	Total	$ 14,048,787	$ 16,275,101	$ 14,871,770	$ 16,275,101	$ 14,871,770
19	Times Interest Earned Ratio	1.299	1.505	1.375	1.505	1.375
20						
21	Debt Service Coverage Ratio:					
22	Net Patronage Capital or Margins	$ 3,236,593	$ 5,462,907	$ 4,059,576	$ 5,462,907	$ 4,059,576
23	Depreciation & Amortization	8,348,168	8,317,632	8,317,632	8,317,632	8,317,632
24	Interest on Long Term Debt	10,812,194	10,812,194	10,812,194	10,812,194	10,812,194
25	Total	$ 22,396,955	$ 24,592,733	$ 23,189,402	$ 24,592,733	$ 23,189,402
26						
27	Interest on Long Term Debt	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194
28	Principal Payments	6,754,044	6,754,044	6,754,044	6,754,044	6,754,044
29	Debt Service	$ 17,566,238	$ 17,566,238	$ 17,566,238	$ 17,566,238	$ 17,566,238
30	Debt Service Coverage Ratio	1.275	1.400	1.320	1.400	1.320
31						
32	Return on Fair Value Rate Base:					
33	Electric Operating Margins	$ 14,042,264	$ 16,173,394 (1)	$ 14,770,063	$ 16,173,394	$ 14,770,063
34	Rate Base	$ 231,844,975	$ 211,802,594	$ 211,802,594	$ 211,802,594	$ 211,802,594
35	Return on Fair Value Rate Base	6.06%	7.64% (1)	6.97%	7.64%	6.97%

(1) Per Direct Testimony of Dennis M. Kalbarczyk.

Arizona Electric Power Cooperative, Inc.

Comparison of Proposed Rates & PPFAC Bases

Test Year Ended March 31, 2009

Description	Col. 1 Company Current Rates	Col. 2 Company As Amended Position Supplemental (2)	Col. 3 Staff Direct Position (3)	Col. 4 Company Rebuttal Position	Col. 5 Staff Surrebuttal Position	Col. 6 Company Rejoinder Position
Collective All-Requirements Members: (1)						
Demand Rate $/kW	$ 14.98	N/A	N/A	N/A	N/A	N/A
Fixed Charge - $/mo.		$ 232,978	$ 931,105	$ 238,793	$ 251,168	$ 238,793
O&M Charge - $/mo.		$ 436,144	$ 1,178,484	$ 414,019	$ 414,019	$ 414,019
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03157	$ 0.03234	$ 0.03156	$ 0.03156	$ 0.03156
Other Resources $/kWh		$ 0.06069	$ 0.06746	$ 0.06170	$ 0.06170	$ 0.06170
PPFAC Bases: (4)						
Current $/kWh	$ 0.01687					
Base Resources $/kWh		$ 0.03377		$ 0.03361		$ 0.03361
Other Resources $/kWh		$ 0.07634		$ 0.07941		$ 0.07941
Partial-Requirements Members:						
Mohave Electric Cooperative						
Fixed Charge - $/mo.	$ 855,113	$ 709,721	$ 764,975	$ 727,283	$ 764,976	$ 727,283
O&M Charge - $/mo. (Present $/kW)	$ 7.26	$ 1,323,724	$ 1,274,882	$ 1,274,882	$ 1,274,882	$ 1,274,882
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03216	$ 0.03215	$ 0.03215	$ 0.03215	$ 0.03215
Other Resources $/kWh		$ 0.06879	$ 0.06879	$ 0.06879	$ 0.06879	$ 0.06879
PPFAC Bases: (4)						
Current $/kWh	$ 0.01603					
Base Resources $/kWh		$ 0.03331		$ 0.03330		$ 0.03330
Other Resources $/kWh		$ 0.07504		$ 0.06971		$ 0.06971
Sulphur Springs Valley						
Fixed Charge - $/mo.	$ 757,429	$ 628,440	$ 677,366	$ 643,991	$ 677,366	$ 643,991
O&M Charge - $/mo. (Present $/kW)	$ 7.26	$ 1,172,125	$ 1,128,876	$ 1,128,876	$ 1,128,876	$ 1,128,876
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03230	$ 0.03229	$ 0.03229	$ 0.03229	$ 0.03229
Other Resources $/kWh		$ 0.06676	$ 0.06676	$ 0.06676	$ 0.06676	$ 0.06676
PPFAC Bases: (4)						
Current $/kWh	$ 0.01603					
Base Resources $/kWh		$ 0.03338		$ 0.03337		$ 0.03337
Other Resources $/kWh		$ 0.07775		$ 0.07241		$ 0.07241
Trico Electric Cooperative						
Demand Rate per kW	$ 14.98	N/A	N/A	N/A	N/A	N/A
Fixed Charge - $/mo.		$ 629,365	N/A	$ 646,435	$ 679,937	$ 646,435
O&M Charge - $/mo. (Present $/kW)		$ 793,509	N/A	$ 764,465	$ 764,465	$ 764,465
Energy Rates:						
Current Energy Rate $/kWh	$ 0.02073					
Base Resources $/kWh		$ 0.03234	N/A	$ 0.03238	$ 0.03238	$ 0.03238
Other Resources $/kWh		$ 0.06612	N/A	$ 0.06604	$ 0.06604	$ 0.06604
PPFAC Bases: (4)						
Current $/kWh	$ 0.01687					
Base Resources $/kWh		$ 0.03331		$ 0.03336		$ 0.03336
Other Resources $/kWh		$ 0.07634		$ 0.09084		$ 0.09084

1) The Fixed Charge and the O&M Charge will be apportioned among the CARMs and allocated to each CARM based upon each CARM's monthly Demand Ratio Share. The Demand Ratio Share will be calculated each month as the percentage of each CARM's 12-month rolling average demand to the total of the CARMs' 12-month rolling average demand.

2) Amended Filing initially included Trico as part of the CARMs. The Company subsequently filed rates that treated Trico as a PRM pursuant to a contract submitted for ACC approval.

3) Staff witness Kalbarczyk did not develop rates for Trico as a PRM in his direct testimony.

4) Staff witness Kalbarczyk did not take issue with the Company's derivation of the PPFAC bases.

BEFORE THE ARIZONA CORPORATION COMMISSION

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-01773A-09-0472

EXHIBIT
MECA
ADMITTED

REBUTTAL TESTIMONY

OF

CARL N. STOVER, JR.

ON BEHALF

OF

MOHAVE ELECTRIC COOPERATIVE, INC.

August 30, 2010

REBUTTAL TESTIMONY OF

CARL N. STOVER, JR.

ON BEHALF OF

MOHAVE ELECTRIC COOPERATIVE, INC.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Carl N. Stover, Jr.; my business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q. By whom are you employed and what is your position?

A. I am employed by C. H. Guernsey & Company, Engineers • Architects • Consultants. I am currently Chairman of the Board. My consulting activities include rate and financial analysis on behalf of our clients before state and regulatory commissions. I am also involved in long-range system planning, power supply planning, and development of power supply resources.

Q. Please briefly summarize your educational background and your professional experience.

A. I have a Bachelor of Science degree in Electrical Engineering and a Master of Science degree in Industrial Engineering. I am a Registered Professional Engineer, licensed in the states of Oklahoma, Kansas, Colorado, Wyoming, Iowa, and Texas. I am a member of the Power Engineering Society and the Engineering Management Society of the Institute of Electrical and Electronics Engineers.

Q. Have you previously appeared before state regulatory commission on matters related to cost of service, rate design and power supply planning?

A. Yes. I have appeared before regulatory commissions in the states of Arkansas, Colorado, Kansas, New Mexico, Oklahoma, Texas and Wyoming. Exhibit CNS-1 attached to this testimony is my resume.

Q. Have you published or presented papers concerning planning, rate design, cost of service, etc.?

A. Yes. *See* Exhibit CNS-1 for a listing of my papers and presentations.

Q. Have you testified before the Arizona Corporation Commission before?

A. I have submitted pre-filed surrebuttal testimony in Docket No. E-04100A-09-0496 related to Southwest Transmission Cooperative's rate filing.

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

A. I am appearing on behalf of Mohave Electric Cooperative, Inc. ("Mohave") an intervenor in this proceeding.

Q. Please describe your experience with Mohave Electric Cooperative, Inc.

A. I began working with Mohave in 2002. My work primarily relates to power supply-related activities including planning for power supply resources, integration of resources, and wholesale rates.

IMPACT OF AEPCO APPLICATION ON MOHAVE

Q. What is the relationship between Mohave and Arizona Electric Power Cooperative, Inc. ("AEPCO")?

A. Mohave is a Class A Member of AEPCO. As a Class A Member, Mohave has a representative on the AEPCO Board of Directors. AEPCO provides a portion of the wholesale power supply necessary to serve Mohave's retail load.

Q. How is Mohave impacted by the proposed AEPCO rate filing?

A. Table 1 below shows the rate impacts proposed by: 1) the AEPCO amended rate filing - 3.1% increase or $1,669,250, 2) Staff - 3.2% increase or $1,736,428, and 3) AEPCO rebuttal 2.37% increase or $1,284,126.

Table 1 – Rate Impact

	MWh	Present	Proposed	Increase	%
AEPCO Amended	---	---	---	---	---
Other Class A	1,729,084	112,413,132	110,647,129	(1,766,003)	-1.57%
Mohave	875,380	54,205,506	55,874,756	1,669,250	3.08%
Total Class A	2,604,464	166,618,638	166,521,885	(96,753)	-0.06%
Other Firm	68,952	3,879,531	3,879,531	-	0.00%
Other Non Firm		4,740,566	4,740,566		
Other Revenue		3,523,943	3,523,943		
Total AEPCO	2,673,416	178,762,678	178,665,925	(96,753)	-0.05%
Staff Proposed					
Other Class A	1,729,084	112,413,132	110,907,704	(1,505,428)	-1.34%
Mohave	875,380	54,205,506	55,941,934	1,736,428	3.20%
Total Class A	2,604,464	166,618,638	166,849,638	231,000	0.14%
Other Firm	68,952	3,879,531	3,879,531	-	0.00%
Other Non Firm		4,740,566	4,740,566		
Other Revenue		3,523,943	3,523,943		
Total AEPCO	2,673,416	178,762,678	178,993,678	231,000	0.13%
AEPCO Rebuttal					
Other Class A	1,729,084	112,413,132	109,956,689	(2,456,443)	-2.19%
Mohave	875,380	54,205,506	55,489,632	1,284,126	2.37%
Total Class A	2,604,464	166,618,638	165,446,321	(1,172,317)	-0.70%
Other Firm	68,952	3,879,531	3,879,531	-	0.00%
Other Non Firm		4,740,566	4,740,566		
Other Revenue		3,523,943	3,523,943		
Total AEPCO	2,673,416	178,762,678	177,590,361	(1,172,317)	-0.66%

SUMMARY OF TESTIMONY

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

A. I am offering rebuttal testimony for the following purposes:

1. To support AEPCO's proposed net margin of $4,059,576 based upon a 1.32 Debt Service Coverage ("DSC") and a revenue decrease of $1,172,317 as set forth in Mr. Pierson's Rebuttal Testimony and summarized on his Exhibit GEP-2.

2. To explain why the Commission should reject ACC Staff's ("Staff") proposed net margin of $5,462,907 based on a 1.40 DSC for a revenue increase of $231,000.

3. To support approval of the amended Partial-Requirements Capacity and Energy Agreements between AEPCO and Mohave and between AEPCO and Sulphur

Springs Valley Electric Cooperative, as well as the new Partial-Requirements Capacity and Energy Agreements between AEPCO and TRICO Electric Cooperative.

Table 2 summarizes the DSC and associated net margins and cash from operations as proposed in the AEPCO amended filing, ACC Staff proposal, and AEPCO rebuttal testimony. Staff is proposing an increase in margins from the AEPCO Amended filing of $2.2 million or approximately 69%. The AEPCO rebuttal proposal increases AEPCO's net margin and cash after debt service approximately $800,000 more than the AEPCO Amended filing.

Table 2 – DSC, Net Margins, and Cash After Debt Service

			(A)	(B)	(C)
		Reference	AEPCO Filed	Staff Proposed	AEPCO Rebuttal
1	Net Margin		$ 3,236,591	$ 5,462,907	$ 4,059,575
2	Plus: Interest	RCS-2, Line17	$ 10,812,194	$ 10,812,194	$ 10,812,194
3	Plus: Depreciation	RCS-2, Line 18	$ 8,348,168	$ 8,317,632	$ 8,317,632
4	Cash Before Debt Service	L1 + L2 + L3	$ 22,396,953	$ 24,592,733	$ 23,189,401
5	Debt Service	L11	$ (17,566,238)	$ (17,566,238)	$ (17,566,238)
6	Cash After Debt Service	L4 + L5	$ 4,830,715	$ 7,026,495	$ 5,623,163
7	DSC	L 4/L11	1.275	1.400	1.320
8	TIER	(L1+L2)/L2	1.299	1.505	1.375
	Debt Service				
9	Principal	RCS-2, Line 21	$ 6,754,044	$ 6,754,044	$ 6,754,044
10	Interest	RCS-2, Line 20	$ 10,812,194	$ 10,812,194	$ 10,812,194
11	Total	L9 + L10	$ 17,566,238	$ 17,566,238	$ 17,566,238

MOHAVE SUPPORTS AEPCO'S REBUTTAL POSITION ON THE LEVEL OF RATE INCREASE

Q. Does Mohave Electric Cooperative support the $1,172,317 decrease in annual revenues requested by AEPCO in its Rebuttal Testimony?

A. Yes.

Q. Do you believe the proposed net margin of $4,059,575 requested by AEPCO, the associated cash from operations after debt service of $5,623,163, and the resulting 1.32 DSC is appropriate.

A. Yes. I believe a DSC of 1.32 is adequate for AEPCO.

Q. Why do you believe it is adequate?

A. The appropriate level of DSC is defined by the margin and cash flow from operations that will allow the Generation and Transmission Cooperative ("G&T") to meet its equity objective, cash reserve objective, and capital credit refund objective, given the projected capital requirements. In order to provide a common basis for evaluation I used some of the factors considered by Staff witness Randall Vickroy but with some modifications that reflect conditions specific to AEPCO.

Q. What are the factors that are unique to AEPCO that need to be considered?

A. First with regard to equity, AEPCO equity as a percentage of capitalization was 29.45% as of 12/31/2009. The rating analysis that Mr. Vickroy references indicates that an equity of between 20% and 35% reflects an A rating which is certainly investment grade. So I believe AEPCO has realized a satisfactory equity level.

With regard to capital credit refunds, AEPCO is not making any capital credit payments to Members so there is no margin requirement to meet a capital credit refund objective.

With regard to capital requirements AEPCO is in a unique situation relative to the typical (G&T). The typical G&T has an obligation to serve future Member load. This means the G&T must provide resource additions to serve load. This mean the G&T must maintain sufficient financial ratios to access capital markets to obtain capital to finance generation resources necessary to serve future Member load growth. On

a going forward basis AEPCO has a much lesser requirement to access capital to finance generation additions to serve future Member load growth since approximately 90% of the AEPCO sales to Class A Members are to Partial Requirement Members (PRM). Under the existing agreements, each PRM has an obligation to find resources to serve load growth.

Another consideration is that AEPCO has no risk uncertainty with regard to future revenue stream. The proposed rate design which has been supported by all parties, including Staff, provides AEPCO certainty with regard to recovery of fixed costs associated with providing service. The future revenue required to recover fixed cost is not dependent on usage. Only those costs that vary as a function of energy usage will be recovered on energy billing units. To provide even more certainty, a significant portion AEPCO's cost (fuel, purchased power fixed and variable cost) and revenue credits (associated with third party sales) are subject to a Fuel and Purchase Power Cost Adjustor (FPPCA) that allows AEPCO to periodically reconcile for changes from the base value reflected in the rates. This does not mean that AEPCO can ignore cost containment issues. A significant portion of AEPCO's fixed costs (such as wages) are not subject to automatic reconciliation and increases in energy sales will not collect any portion of these fixed costs. Therefore, it will be imperative that AEPCO control costs.

With regard to meeting coverage objectives, AEPCO has a requirement to maintain a 1.0 DSC to meet RUS mortgage obligations (Reference Direct Testimony of Randall Vickroy Page 3, Line 17). In the last rate case the Commission approved a 1.13 DSC. Staff testimony indicates a 1.25 DSC is sufficient for investment grade rating. *See* Vickroy Direct at 12, line 22 -13, line 14 and 15, lines 8 – 11. A 1.32 DSC would provide for adjustments to reflect other factors in the rating valuation process.

The final consideration is the ability to maintain cash reserves. The ability to realize necessary cash reserves should be enhanced with a 1.32 DSC because this means cash flow from operation will actually be approximately $800,000 greater than the AEPCO Amended proposal.

STAFF'S PROPOSED NET MARGIN AND DSC RESULTS IN AN UNREASONABLE AND UNNECESSARY RATE INCREASE

Q. Why do you believe the proposed Staff recommendation of a 1.40 DSC is inappropriate?

A. Mr. Vickroy determines a 1.25 DSC could be appropriate to maintain investment grade rating based on the Financial Metrics criteria. *See* Vickroy Direct at 12, line 22 through 13, line 14. He then develops a range of 1.25 – 1.45 as being reasonable. *Id.* at 15, line 8. He never describes why the 1.45 is the appropriate upper bound. However, he then develops adjustments related to qualitative factors which results in his concluding that a 1.40 DSC is within his defined range and is appropriate. I believe his adjustments are excessive and not supported by the data presented in this proceeding. I believe that appropriate consideration of the qualitative factors that he applies would result in the conclusion that a 1.32 DSC is adequate.

Q. Please provide more detail as to how Mr. Vickroy develops his recommended 1.40 DSC?

A. He states that he evaluated AEPCO's "...coverage requirements based on risk evaluation techniques used by the credit rating agencies." *See* Vickroy Direct at 8, lines 10 – 11. He states that using both quantitative criteria and qualitative criteria he established a range of DSC ratios. He then considered "...AEPCO's current prospects (as indicated by its projected capital expenditure program, cash situation, other contingencies)..." to develop a recommended DSC level and its commensurate cash flow within the range. *See* Vickroy Direct at 8, line 24 through 9, line 2.

Q. Does Mr. Vickroy identify the specific criteria that will be used in his analysis?

A. Yes. He provides not only the criteria but also the weighting that should be given to each criteria. They are:

1. Financial Performance and Metrics (40%)
2. Long-term Wholesale Power Supply Contracts / Regulatory Status (20%)
3. Rate Flexibility (20%)
4. Member Profile (10%)
5. Size (10%)

Q. What is the source of the criteria and the weighting factors used by Mr. Vickroy?

A. Mr. Vickroy does not provide a specific reference; however, the criteria and weighting factors can be found in a rating methodology report published by Moody's Investment Services for U.S. Electric Generation & Transmission Cooperatives, published in December 2009. A copy is attached as Exhibit CNS-2.

Q. Please describe Mr. Vickroy's general process in developing his recommendation.

A. He begins with an analysis based on the Financial Performance and Metrics. He states that, "The rating mid-point DSC coverage, for instance, is 1.25, as compared to the company's request of 1.275. Based solely upon the quantitative metrics, AEPCO's rate request could produce financial results that would qualify the Cooperative for an investment-grade credit rating in either the Baa or A categories." *See* Vickroy Direct at 13, lines 11 - 14. He states that, "However, we have yet to account for numerous qualitative factors and AEPCO business factors that can influence these quantitative results upward or downward." (*See* Randall Vickroy's Direct Testimony Page 13, line 14). After accounting for the qualitative results the 1.25 DSC value is adjusted upward to a DSC of 1.40.

Q. Please describe Mr. Vickroy's assessment of the qualitative factors and specific factors that caused him to increase the DSC from 1.25 to 1.40.

A. Table 3 summarizes the criteria, Mr. Vickroy's assessment of criteria in terms of impact on rating level, and specific references to his testimony. There are actually ten criteria considered in both the Moody's report and Mr. Vickroy's testimony in addition to the criteria related to Financial Metrics.

Table 3 – Criteria Referenced by Vickroy

Ref	*Criteria*	*Impact*	*Testimony Ref*
2a	Long Term Contracts	Positive	P14, L 3
2b	Regulatory Status	Negative	P14, L5
3a	Rate Flexibility: Board involvement/Rate Adjustment Mechanisms	Baa	P14, L12
3b	Rate Flexibility: New construction build exposure	Baa	P14, L12
3c	Rate Flexibility: Competitiveness	Baa – Ba	P14, L13
3d	Rate Flexibility: Purchased Power Percentage	Positive	P14, L15
4a	Member Profile: Percentage of Retail Sales	Positive	P14, L17
4b	Member Profile: Member Capitalization	Baa	P14, L19
5a	Size: Energy Sales	Negative	P14, L21
5b	Size: Net Plant	Negative	P14, L21

Mr. Vickroy summarizes his analysis by stating, "The nonfinancial rating factors evaluated here indicate that AEPCO carries significant levels of added risk due to its regulatory status, rate flexibility criteria, and small sales and asset bases." (*See* page 15, line 1.) He apparently makes his upward adjustment based on criteria 2b, 3c, 5a, and 5b.

Q. There are a total of ten criteria to consider. He identifies four as having a negative impact. Does he appear to consider factors that have a positive impact?

A. I could not find any reference in his testimony to how he might have weighted the factors with a positive impact as offsets to the four factors that have a negative impact.

Q. Do you have comments related to evaluation of the four qualitative factors that Mr. Vickroy uses to justify the increase the DSC requirement?

A. Yes. Let me begin with Regulatory Status criteria. Mr. Vickroy makes the general statement that Moody's considers being rate regulated as a negative factor for purposes of ratings. (*See* Vickroy Direct at 14, line 5.) The fact is that based on Moody's analysis an entity that is rate regulated can qualify for an A rating. *See* CNS-2 at 8, Factor 1 Chart.

Rather than regulation resulting in a rating below investment grade, the issue appears to be how the regulatory commission deals with the cooperative. In order to qualify for a below-investment grade rating, the environment for a Ba rating the regulatory condition as defined by Moody's would be "Unsupportive Commission Practices, Generally Difficult Regulatory Relationships" or for a B rating "Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships." *See* CNS-2 at 8, Factor 1 Chart. Mr. Vickroy does not indicate why he views the ACC regulatory condition as having a negative impact. It is interesting to note that even with a negative rating for regulation, his evaluation of contract status and regulatory status results in a Baa category. *See* Vickroy Direct at 14, lines 4 – 8.

Q. How do you view the relationship between the ACC and AEPCO?

A. This is my first opportunity to testify before the ACC so I have no personal experience. I can reference what has actually happened to AEPCO under ACC rate regulation. The current rates paid by the AEPCO Class A Members became effective with the first phase in 9/2005, the second phase in 9/2006, and the third phase in 9/2007. Given the rate the ACC approved (reference Exhibit LCG -2):

1. The financial ratios have improved significantly from a 12/31/2003 value:
   a. Equity increased from 4.77% to 29.45%
   b. DSC increased from 0.56 to 1.70
2. The ACC also approved a flow through provision that allows flow through (subject to ACC approval) of:
   a. All changes in fuel cost
   b. All changes in purchased power cost
   c. All changes in transmission cost associated with purchased power
   d. All changes in impact related to sales to third parties

The ACC regulatory actions have resulted in AEPCO realizing a significant improvement in financial ratios under the rates last approved by the ACC. Even more importantly the ACC allows AEPCO full recovery of changes (either increase or

decrease) of a major component of cost of service. The adjuster even allows for recovery of any changes (reduced margins) associated with third-party sales. It would not appear that ACC regulation has had an adverse impact on AEPCO's ability to recover cost and improve earnings.

Therefore, I believe that Mr. Vickroy has overstated the negative impact of regulation in general. Based on actual financial performance, it also appears that he has overstated the specific impact on AEPCO of ACC regulation. I am not sure what has caused him to classify the ACC/AEPCO relations as Unsupportive Commission, Generally Difficult Regulatory Relationships, or Very Unsupportive Commission Practices, Often Contentious Regulatory Relationships.

Q. What are your comments related to rate Flexibility Criteria?

A. There are four subcomponents under this classification and three of these are given investment grade status or a positive rating by Mr. Vickroy. His negativity relates to competitiveness. *See* Vickroy Direct at 14, lines 13 – 14.

In reviewing the Moody's analysis there is a criterion for a "Potential for Rate Shock Exposure." Moody's indicates that the potential for rate shock exposure is linked to rate competitiveness so they combined the two. *See* CSN-2 at 8. There appears to be two issues this criterion addresses:

1. A G&T may have very competitive rates but be exposed to a substantial rate shock because of rate increase.
2. A G&T could have higher rates than other providers in the area.

Mr. Vickroy is not clear as to how he is applying these criteria. He has not provided any comparison of AEPCO rates with other suppliers in the area. Even given the ACC Staff proposal resulting in a rate increase of 0.14%, there is no suggestion of major rate shock. Therefore, there does not seem to be any support for suggesting a negative rating for these criteria.

Q. The third criterion supporting an increase in DSC is related to size. Do you agree with Mr. Vickroy's adjustment for this criterion?

A. No. Again, referencing the Moody's report related to G&T size the report states, "Size, together with Factor 3 Member Profile, has the lowest weighting of the five

key factors because it tends to be less important for entities, such as G&T coops, that are subject to limited competition." *See* CSN-2 at 14. The report again goes on to say that size does matter in that the greater number of energy sales the greater the base over which to spread cost, and the greater the size the greater the opportunities for a large pool of diversified assets and diversity of fuel resources.

AEPCO is small compared to other G&Ts. However, I think it is important to note that with diversity as a major objective, AEPCO has been able to achieve diversity of fuel with a portfolio of coal, gas, and hydro which provides a great deal of fuel diversity benefits to its Members. In addition, AEPCO has a mix of owned and purchased power assets in place to serve its Members. Therefore, certain of the factors that large size is intended to capture in the Moody methodology, I believe AEPCO has been able to capture even with their relative small size.

Q. Are there other factors that are specific to AEPCO that you believe need to be considered in establishing the appropriate DSC level?

A. Yes. The conditions that typically relate to a G&T are:

1. The G&T has an obligation to provide power supply resources to serve the Member's retail load.
2. The G&T obligation is to assume the volume risk and be responsible to serve the Member load whatever the load might be.
3. Because of the obligation to serve Member load, the G&T must make sure it has access to capital necessary to finance the asset additions required to serve load.
4. Therefore, the G&T must:
   a. If a G&T can finance through RUS/FFB/CFC/CoBank, maintain adequate financial ratios to meet debt indenture requirement.
   b. If a G&T must go to the markets to finance, maintain adequate financial ratios to access the markets at favorable interest rates which means maintaining investment grade ratings.

AEPCO, unlike most other G&T's:

1. Does not have responsibility to serve all of the Member retail load growth.
2. Does not have volume risk uncertainty for a large portion of Member load.

This is because approximately 90% of the Class A Member load will be served under a PRM service obligation (Mohave, TRICO, SSVEC). AEPCO does not have a contractual obligation to access capital markets for major capital additions to serve load growth associated with these three Members. In addition, a PRM service agreement eliminates AEPCO's volume risk uncertainty associated with changes in existing retail load for these members.

Q. Are there any other factors that should be considered?

A. Yes, in the last rate case in Docket No. E-01773A-04-0528 the Commission determined that a DSC of 1.13 was appropriate. The Commission determined this was appropriate given a G&T with the equity of approximately 5%. ACC Staff is now suggesting a 1.40 DSC with an equity of approximately 30%.

Q. Does Mr. Vickroy have any other justifications for his proposed 1.40 DSC?

A. Yes. He indicates that he believes the $3.2 million margin and $4.8 million cash from operations as proposed by AEPCO is too thin from a cash flow perspective and would provide little cushion to cover unexpected operating problems and contingencies. *See* Vickroy Direct at page 16, lines 12 - 16. Mr. Vickroy apparently believes that approximately $2.2 million should be added to the revenue requirement to account for future events that are not reflected in the test year. He is using the margin component of the revenue requirement to provide a cushion to deal with future speculative contingencies.

Q. Does Mr. Vickroy have any comment about cash situation on a going forward basis?

A. Yes. He states "I do not believe, however, that the cash situation is quite so dire on a going forward basis." *See* Vickroy Direct at 16, line 23.

Q. What are your conclusions with regard to the basis for Mr. Vickroy's recommendation of a 1.40 DSC?

A. His justification for adjustment from 1.25 to 1.40 appears to be based on four criteria that he views as a basis for the upward adjustment. He does not consider the other six criteria as providing any positive pressures that could offset the upward adjustment. Of the four factors he does not provide any basis for the negative view of competitiveness criteria. There is clearly no basis in terms of a rate shock and no

evidence presented that AEPCO wholesale rates are not competitive with other wholesale rates offered for similar service. With regard to the size criterion, I believe that AEPCO has been able to realize the diversity attributes (fuel and ownership) typically assumed to drive this criterion. This leaves the negative adjustment related to ACC regulation of AEPCO. As I have indicated, actual experience does not seem to suggest that regulation has had an adverse impact on AEPCO sufficient to justify the DSC adjustment Mr. Vickroy is proposing. In fact Mr. Vickroy indicates that the contract and regulatory criteria combined result in an investment grade rating. I believe that AEPCO's proposed DSC of 1.32 is sufficient. It produces a margin of $4,059,575 and a cash flow from operations of $5,623,163.

SHOULD THE COMMISSION APPROVE THE AMENDED AND NEW PARTIAL-REQUIREMENTS CAPACITY AND ENERGY AGREEMENTS

Q. On June 2, 2010, AEPCO, Mohave, SSVEC and TRICO filed a Joint Request for Contract/Amendments Approvals and Revised Rates Request. Please briefly explain the nature of that filing.

A. For the past four years, AEPCO and its members have been involved in sometimes heated negotiations over the allocation of costs. Last year TRICO gave notice that it was converting from an all to a partial requirements member. The Amendments with the Mohave and SSVEC agreements, the new Partial-Requirements Capacity and Energy Agreement with TRICO, as well as the amendments to the all-requirements Wholesale Power contracts between AEPCO and Duncan Valley Electric Cooperative, Inc. and AEPCO and the Graham County Electric Cooperative, Inc. collectively implement agreed upon changes to the cost allocation and rate design. These changes are reflected in the rates now being proposed by AEPCO in this docket. The amendments and new contract resolve disputes that arose under existing agreements and have substantially reduced the issues that would have been raised in connection with AEPCO's initial filing.

Q. Why should the Commission approve the amendments and the contract?

A. The agreements benefit the Parties and the public by providing for a fair, equitable and repeatable allocation of costs and revenues between the PRMs and ARMS based on principles of cost causation, while providing AEPCO with fair and reasonable recovery of its revenue requirements and sufficient operating margins.

Q. Do you reserve comment on other aspects of AEPCO's rebuttal testimony?

A. Yes. Neither Mohave nor I have seen the rebuttal testimony being filed by AEPCO simultaneously with my rebuttal testimony. Therefore, except to the extent specifically adopted and supported in my testimony, Mohave and I expressly reserve the right to comment thereon in rejoinder testimony or at hearing.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT CNS-1

EDUCATION:

M.S., Industrial Engineering, The University of Oklahoma, 1969
B.S., Electrical Engineering, The University of Oklahoma, 1963
Stanford University School of Business Administration, "Leading Change and Organizational Renewal," Summer 2001.
Harvard Business School Executive Education, "What's Next & So What? – Leading in the 21st Century," January 2000.
Harvard Graduate School of Business Administration, "Leadership in Professional Service Firms," June 1995.

REGISTRATIONS:

Professional Engineer: Colorado - 12931, Iowa - 11754, Kansas - 6261, Oklahoma - 8526, Texas - 67676, Wyoming - 1215

PROFESSIONAL ACTIVITIES / HONORS:

Associate Member, National Rural Electric Cooperative Association, 1998 - Present
Associate Member, American Public Power Association, 1997 - Present
Member, College of Engineering Board of Visitors, The University of Oklahoma, 1989 - Present
Member, Chairman; Electric Power Advisory Board, School of Electrical Engineering and Computer Science, The University of Oklahoma, 1985 - Present
Member, Institute of Electrical and Electronics Engineers, 1970 – Present
Distinguished Graduates Society Inductee, College of Engineering, The University of Oklahoma, 1998

EXPERIENCE RECORD:

1966 - Present **C. H. Guernsey & Company, Oklahoma City, Okla.**

2005-Present, Chairman of the Board
1990-2005, Chairman of the Board, CEO and President
1989-1990, President, Board of Directors
1980-1989, Executive Vice President, Board of Directors
1972-1980, Vice President, Board of Directors

Mr. Stover's primary areas of responsibility include preparation of retail and wholesale rate analysis for regulated and unregulated systems, strategic planning, financial analysis and forecasting, resource planning and power supply negotiations, and training for utility clients. Mr. Stover has appeared before the Arkansas, Colorado, Kansas, Oklahoma, Texas, Utah and Wyoming state commissions, as well as the Federal Energy Regulatory Commission.

1963 - 1966 USAF. Assigned to Inertial Guidance Laboratory at Holloman AFB, New Mexico.

Lt. Stover served as engineer in testing and evaluation of inertial guidance systems, and received an honorable discharge as 1st Lieutenant.

SPECIFIC CONSULTING EXPERIENCE:

Rate Proceedings – Distribution Cooperatives

Arkansas (Arkansas Public Service Commission)

- Ozarks Electric Cooperative Corporation, Fayetteville (Docket 86-162-U)

COLORADO (Colorado Public Utilities Commission)

- Delta-Montrose Electric Association, Delta
- Empire Electric Association, Inc., Cortez
- Gunnison County Electric Association, Inc., Gunnison
- Holy Cross Electric Association, Inc., Glenwood Springs
- Intermountain Rural Electric Association, Sedalia
- La Plata Electric Association, Inc., Durango
- Moon Lake Electric Association, Inc., Roosevelt, UT
- Poudre Valley Rural Electric Association, Inc., Ft. Collins
- San Isabel Electric Association, Inc., Pueblo
- San Luis Valley Rural Electric Cooperative, Inc., Monte Vista
- San Miguel Power Association, Inc., Nucla
- United Power, Inc., Brighton
- White River Electric Association, Inc., Meeker

Illinois

- Egyptian Electric Cooperative Association, Steeleville
- SouthEastern Illinois Electric Cooperative, Inc., Eldorado
- Southern Illinois Electric Cooperative, Dongola

Indiana (Indiana Public Service Commission)

- Clark County Rural Electric Membership Corporation, Sellersburg

Kansas (Kansas Corporation Commission)

- Ark Valley Electric Cooperative Association, Inc., Hutchinson
- C.M.S. Electric Cooperative, Inc., Meade
- D.S.&O. Rural Electric Cooperative Association, Inc., Solomon
- Lane-Scott Electric Cooperative, Inc., Dighton
- Ninnescah Rural Electric Cooperative Association, Inc., Pratt
- Sedgwick County Electric Cooperative Association, Inc., Cheney
- Sumner-Cowley Electric Cooperative, Inc., Wellington
- Victory Electric Cooperative Association, Inc., Dodge City
- Western Cooperative Electric Association, Inc., WaKeeney

Nebraska

- McCook Public Power District, McCook
- Panhandle Rural Electric Membership Corporation, Alliance
- Twin Valleys Public Power District, Cambridge

Oklahoma (Oklahoma Corporation Commission)

- Caddo Electric Cooperative, Binger
- Canadian Valley Electric Cooperative, Seminole
- Central Rural Electric Cooperative, Stillwater
- Cimarron Electric Cooperative, Kingfisher
- Cookson Hills Electric Cooperative, Inc., Stigler
- Cotton Electric Cooperative, Walters
- East Central Oklahoma Electric Cooperative, Inc., Okmulgee
- Harmon Electric Association, Inc., Hollis
- Indian Electric Cooperative, Inc., Cleveland
- Kay Electric Cooperative, Blackwell
- Kiwash Electric Cooperative, Inc., Cordell
- Lake Region Electric Cooperative, Inc., Hulbert
- Northeast Oklahoma Electric Cooperative, Inc., Vinita
- Northfork Electric Cooperative, Sayre
- Northwestern Electric Cooperative, Inc., Woodward
- Oklahoma Electric Cooperative, Norman
- Oklahoma Gas & Electric Company, Cause No. 29450
- People's Electric Cooperative, Ada
- Red River Valley Rural Electric Association, Marietta
- Rural Electric Cooperative, Inc., Lindsay
- Southwest Rural Electric Association, Inc., Tipton
- Sun Oil vs. Arkansas Louisiana Gas Company
- Verdigris Valley Electric Cooperative, Inc., Collinsville

South Dakota

- West Central Electric Cooperative, Inc., Murdo

Texas (Public Utility Commission of Texas)

- Bailey County Electric Cooperative Association (2915, 5003, 7900)
- Bandera Electric Cooperative, Inc. (2786, 4279)
- Bluebonnet Electric Cooperative, Inc. (266, 4070, 7415, 12126)
- Central Texas Electric Cooperative, Inc. (3170, 6363, 7661, 10325, 12127)
- Cherokee County Electric Cooperative Association (817)
- City of Austin (6560 - in behalf of Bergstrom AFB
- Coleman County Electric Cooperative, Inc. (4875, 13335)
- Comanche County Electric Cooperative, Inc. (5272, 8272)
- Concho Valley Electric Cooperative, Inc. (3550, 4797, 6540, 9056, 13334)
- Cooke County Electric Cooperative Association (9240)
- CoServ Electric (3470, 4189, 5165, 9892, 21669)

- Deaf Smith Electric Cooperative, Inc. (4481, 5019, 8354)
- Department of Defense (Bergstrom AFB v. City of Austin (6560)
- Fannin County Electric Cooperative, Inc. (3747, 4940, 9992)
- Farmers Electric Cooperative, Inc. (3780, 4422, 5259, 6475)
- Fort Belknap Electric Cooperative, Inc. (4396, 6558, 9944)
- Grayson-Collin Electric Cooperative, Inc. (3945, 6510)
- Greenbelt Electric Cooperative, Inc. (5038, 9930, 10405)
- Guadalupe Valley Electric Cooperative, Inc. (398, 3397, 4516, 6338, 7550)
- Hamilton County Electric Cooperative Association (5971)
- HILCO Electric Cooperative, Inc. (7154)
- Houston Lighting and Power Company (5779 and 8425)
- Jackson Electric Cooperative, Inc. (2753, 4710, 10561)
- Lamb County Electric Cooperative, Inc. (3270)
- Lighthouse Electric Cooperative, Inc. (2995, 4612, 8097)
- Lyntegar Electric Cooperative, Inc. (2988, 4564)
- Magic Valley Electric Cooperative, Inc. (1991, 3212, 5477, 20281, 20314)
- Medina Electric Cooperative, Inc. (4113, 11048)
- Big County Electric Cooperative (formerly Midwest) (2717, 3711, 6983)
- Navarro County Electric Cooperative, Inc. (3116)
- Navasota Valley Electric Cooperative, Inc. (7355)
- North Plains Electric Cooperative, Inc. (2934, 4958, 5214)
- Nueces Electric Cooperative, Inc. (3936, 5203, 23454)
- Pedernales Electric Cooperative, Inc. (2247, 3437, 5109)
- Rio Grande Electric Cooperative, Inc. (521, 3681)
- Rita Blanca Electric Cooperative, Inc. (2527, 8422)
- Rusk County Electric Cooperative, Inc. (3383)
- San Bernard Electric Cooperative, Inc. (2699, 3692, 4534, 5467, 6218)
- South Plains Electric Cooperative, Inc. (2936, 4822, 6985)
- Southwest Texas Electric Cooperative, Inc. (5335)
- Swisher Electric Cooperative, Inc. (3062, 6796)
- Taylor Electric Cooperative, Inc. (3679, 5767, 9159)
- Victoria Electric Cooperative Company (770, 3949, 6680)
- Wharton County Electric Cooperative, Inc. (4541, 6685)

<u>Utah</u> (Utah Public Service Commission)

- Empire Electric Association, Inc., Cortez, Colo.
- Moon Lake Electric Association, Inc., Roosevelt

<u>Wyoming</u> (Wyoming Public Service Commission)

- Big Horn Rural Electric Company (9076)
- Bridger Valley Electric Association, Inc. (9447)
- Carbon Power & Light, Inc. (9022)
- Garland Power & Light, Inc. (9575)
- High Plains Power
- Niobrara Electric Association, Inc. (9572)
- Wheatland Rural Electric Association (9574)

- Wyrulec Company (9097)

Rate Proceedings – Municipal Utilities

- Altus, Okla.
- AWC of LCRA, Texas
- Blackwell, Okla.
- Braman, Okla.
- Bryan, Texas
- Chanute, Kans.
- Chatham, Ill.
- Cody, Wyo.
- Cushing, Okla.
- Fredericksburg, Texas (7661, Certification - Central Texas EC)
- Lamar, Mo. vs. SWPA
- Larned, Kans.
- New Braunfels Utilities, Texas
- Oklahoma Municipal Power Authority, Okla.
- Osborne, Kans.
- Piedmont Municipal Power Authority, S. Car.
- Ponca City, Okla.
- Raton, N. Mex.
- Riverton, Ill.
- Stillwater, Okla.
- Torrington, Wyo.
- Vernon, Texas
- Wellington, Kans.

Rate Proceedings - Wholesale

Arkansas (Arkansas Public Service Commission)

- Arkansas Electric Cooperative Corporation Docket Nos. U-3071, 83-023-U

Colorado

- Tri-State G&T Association, Inc. Docket No. 98A-511E

Illinois

- Southern Illinois Power Cooperative

Iowa

- Corn Belt Power Cooperative, Inc.
- Northwest Iowa Power Cooperative, Inc.

Kansas

- Kansas Electric Power Cooperative, Inc.

Louisiana

- Cajun Electric Power Cooperative, Inc. Docket No. U-17735

Minnesota

- Great River Energy

Missouri

- M & A Electric Power Cooperative

New Mexico

- Plains Electric G&T Cooperative, Inc. Merger with Tri-State G&T Assn.

Nebraska

- Nebraska Electric G&T Cooperative, Inc., Columbus

North Carolina

- North Carolina Electric Membership Corporation

North Dakota

- Basin Electric Cooperative, Inc.
- Central Power Electric Cooperative, Inc.

South Dakota

- Rushmore Electric Power Cooperative, Inc.

Texas (Public Utility Commission)

- Brazos Electric Cooperative Docket Nos. 4079, 8868, 12757, 13100, 22531
- Central and South West Corp. / American Electric Power Company Docket No. 19265
- Golden Spread Electric Cooperative Docket Nos. 13444, 14980, 15100, 16738
- Lower Colorado River Authority Docket Nos. 366, 1521, 2503, 3522, 3838, 6027, 7512, 8032, 8400, 9427
- Rayburn Country Electric Cooperative Docket No. 7361
- San Miguel Electric Cooperative, Inc. Docket No. 4127, 5351
- South Texas Electric Cooperative, Inc. Docket Nos. 4128, 5077, 5387, 5440, 8952, 22344
- Southwestern Electric Service Company Docket No. 2817
- Southwestern Public Service Company Docket Nos. 4387, 6055
- Texas Electric Service Company Docket Nos. 527, 1903, 2606, 3250, 4097, 5200
- Texas Power & Light Company Docket Nos. 3006, 3780, 4321
- Texas Utilities Electric Company Docket Nos. 5640, 9300, 13100
- Texland Electric Cooperative, Inc. Docket No. 3896
- West Texas Utilities Company Docket No. 4716

Utah

- Deseret G&T Cooperative, Inc. Docket No. OA97-3-000; Docket No. 98-2035-04 PacifiCorp / ScottishPower Merger

Rate Proceedings - Federal Power Commission (Federal Energy Regulatory Commission)

- Cajun Electric Power Cooperative vs. Gulf States Utilities Company Docket Nos. EL87-051, ER88-477

- Central and South West Services — Docket No. ER84-031
- Central Power & Light Company — Docket Nos. ER77-331, ER81-387, ER86-721
- El Paso Electric Company — Docket Nos. ER76-409, ER77-488, ER79-526, ER81-426, ER84-236, ER86-368
- Golden Spread Electric Cooperative — Docket Nos. ER87-396, EL89-050 EL95-24
- Oklahoma Gas & Electric Company — Docket Nos. ER77-127, ER77-215, ER78-423, ER80-421, ER82-256, ER84-541
- Public Service Company Colorado — Docket Nos. ER76-381, ER76-687, ER78-507, ER80-407
- Public Service Company Oklahoma — Docket Nos. ER77-422, ER78-511, ER82-545
- Southwestern Public Service Co. — Docket Nos. ER84-604, ER85-477, EL89-051
- West Texas Utilities Company — Docket Nos. ER80-038, ER82-023, ER82-708, ER83-694, ER84-236, ER85-081, ER87-065

Transmission Wheeling / Interconnection Analysis

- Central and South West Services, Inc. — Docket No. EL79-008, ER82-545, et.al.
- LCRA Wheeling Case before the Texas PUC — Docket No. 6995

Power Supply Planning

A. System Resource Planning:

- Golden Spread Electric Cooperative, Inc.: Notice of Intent (PUCT Docket No. 13444)
- Golden Spread Electric Cooperative, Inc.: Exempt Wholesale Generation Contract Certification (PUCT Docket No. 15100)
- Holy Cross Energy and Yampa Valley Electric Association, Colorado
- South Texas Electric Cooperative, Texas

B. Long-Range Power Cost - 20-Year Forecast:

- Golden Spread Electric Cooperative, Inc. — Southwestern Public Service Company
- Mid-Tex G&T Electric Cooperative, Inc. — West Texas Utilities Company and Brazos Electric Cooperative
- Magic Valley Electric Coop., Inc. — South Texas Electric Coop., Inc.
- Rio Grande Electric Cooperative, Inc. — Central Power & Light Company
- Magic Valley Electric Cooperative, Inc. — City of Brownsville/Central Power & Light Co.

C. Other Power Supply Planning Projects:

- Golden Spread Electric Cooperative, Inc., TX — Mustang Station
- Magic Valley Electric Cooperative, Inc., TX — Magic Valley Station

Training

Training – NRECA

"Financial Planning and Strategies Workshop," presented for NRECA's Management Internship Program, Madison, Wisconsin; Yearly in May: 2005, 2006, and 2007.

"Financial Strategy and Rate Design for a Competitive World," presented for NRECA's Financial Planning and Strategies Workshop; Lincoln, Nebraska; Yearly in May: 2000, 2001, 2002 and 2004.

"Rate Design in a Restructured Environment," presented for NRECA's Management Internship Program; Lincoln, Nebraska; Yearly: 1999-2001.

"Financial Strategy and Rate Issues for the Changing Utility Industry," NRECA's Advanced Financial Planning; Lincoln, Nebraska; 1997-99.

"Rate Issues and Strategy for the Changing Utility Industry," NRECA's Management Internship Program; Lincoln, Nebr., 1987-98.

"Identifying Revenues and Costs Associated with Marketing Solutions," NRECA's Strategic Marketing Planning for Management Conference; Lincoln, Nebr., 1996-97.

"Application of Market-Based Rates in a Competitive Utility Industry," presented to NRECA's Tech Advantage '97 Annual Meeting; Las Vegas, Nevada; March 15, 1997.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; 1990-96.

"Power Supply Issues in the U.S. and Abroad - Increasing Competition and Deregulation," for Management and Technical Issues Conference for International Guests at 1996 NRECA Annual Meeting; Houston, Texas; March 23, 1996.

"Rates and Related Issues," for Management and Technical Issues Conference for International Guests at 1996 NRECA Annual Meeting; Houston, Texas; March 23, 1996.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; 1986-96.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA's Summer School; New Orleans, La., June 30-August 1, and Hilton Head, S.C., July 18-19, 1995.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA G&T Rates Conference; Lincoln, Nebr., June 20-21, 1995.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA G&T Rates Conference; Lincoln, Nebr., June 14-15, 1994.

"Competing in the '90s and Beyond," 1994 NRECA G&T Rates Conference; San Antonio, Texas; June 5-8, 1994.

"Implementation of Demand-Side Component of IRP," NRECA's Finance for Marketing Professionals Workshop; Lincoln, Nebr.; 1993-95.

"Competing for Retail Loads," NRECA's 1994 G&T Legal Seminar; New Orleans, La., November 10, 1994.

"Transmission Access Revolution," NRECA's 1993 G&T Director's Update Conference; Nashville, Tenn.; December 2, 1993.

"Coordination of IRP and Marketing Strategy with G&T Wholesale Rate Design," NRECA's G&T Rates & G&T Marketing Conference; Lexington, Ky.; June 8, 1993.

"Rates as a Marketing Tool," NRECA's G&T Marketing Seminar; Denver, Colo.; September 10, 1992.

"Development of a Rate Strategy for the Cooperative System," 1991 Rural Electric Expo for NRECA; New Orleans, La.; February 2-3, 1991.

"Innovative Rate Forms," 1991 NRECA Engineering and Operations Conference; New Orleans, La.; January 31, 1991.

"Making Sense of Your System's Rate Structure," NRECA 1990 Member Services Communication Conference; Charlotte, N.C.; July 31, 1990.

"Service to Large Industrial Customers," NRECA's Rural Electric Management Council; Fargo, N. Dak.; May 17, 1989.

"Rate Design for Attracting and Maintaining Loads," NRECA's Management Internship Program; Lincoln, Nebr.; October 1, 1986.

"Preconference Workshop: Basic Issues in Rate Design," NRECA's 1986 National Accounting and Finance Conference; Tampa, Fla.; September 9, 1986.

"Marketing: Distribution Benefits Through Sale of Surplus Power and Jointly Designed Marketing Rates," 1987 NRECA Engineering and Operations Conference; Denver, Colo.; November 20, 1987.

Training - International

Rate Training Course presented for electric utility executives of Russia, coordinated through Institute of International Education; Moscow, Russia; November 1994.

Rate Training Course presented for electric utility executives of India, coordinated through Institute of International Education; Hyderabad, India; November 1994.

Rate Training Course presented for members of Bangladesh REB coordinated through NRECA; Oklahoma City, Okla.; October 28-November 8, 1991.

"Development of Rate Schedules for an Electric Utility," CAST/CSEE/NRECA Workshop; Kunming, Republic of China; May 14-19, 1984.

"A Planning Model for the Analysis of Long Range Distribution System Design Alternatives," IEEE PES Summer Meeting and EHV/UHV Conference; Vancouver, Canada; July 1973.

Presentations and Papers

"Rate Analysis and Cost of Service Study," presented with Judy Lambert to Region VIII Electric Cooperative Accountants' Association, in Oklahoma City, Okla., April 12, 2002.

"How to Position Cooperatives to Compete in a Customer-Choice Environment," presented to the Texas Statewide group in Austin, Texas; April 11, 2002.

"Positioning The Member Distribution Cooperative to Deal with a Customer Choice Environment," Panel discussion at Brazos Electric Cooperative's Strategic Planning Workshop; Waco, Texas; October 5, 2001.

"Restructuring Issues for the G&T," presented for G&T Accounting and Finance Association's 2000 Conference; Breckenridge, Colorado; June 19, 2000.

"The Restructuring of the Electric Power Industry in Oklahoma and in the Southwest," Panel Discussion Participant; Institute for Energy Economics and Policy, et al; Sarkeys Energy Center, The University of Oklahoma, Norman; December 10, 1999.

"Application of Leadership Skills," presentation for Dr. Jerry Holmes' engineering students at The University of Oklahoma, Norman; April 22 and December 2, 1999.

"Rate Design and the Changing Electric Industry," WREA Annual Meeting; Cheyenne, Wyoming; September 24, 1998.

"Rate Design and the Changing Electric Industry," CFC's Annual Meeting; Colorado Springs, Colorado; July 3, 1998.

"Preparing for the Future Cooperative Electric Service in Texas," presented to Texas Electric Cooperatives' Managers' Conference; Austin, Texas; December 5, 1996.

"Industry Restructuring Implications for Cooperatives," presented to Texas Electric Cooperatives' Government Relations Committee; Austin, Texas; July 1, 1996.

"The Economics of Serving Large Loads," Electric Cooperatives of South Carolina's Competitive Strategies Workshop, Columbia, S.C., August 15-16, 1995.

"Evolving Cooperative Structures," CFC's Cooperative Financing Forum; Chicago, Ill.; July 11, 1995.

"Takeover Workshop," Texas Electric Cooperatives, Inc.; Lubbock and Cleburne, Texas; April 6-7, 1995.

"The Power in the Partnership: Changing the Co-Op Power Supply," TEC 54th Annual Meeting; Fort Worth, Texas, August 2, 1994.

"Implementation of Demand-Side Component of IRP," Georgia EMC in coordination with NRECA; Ga., April 27, 1994.

"The Transmission Access Revolution," Special G&T Director's Update Program for Brazos Electric Power Cooperative, DFW Airport Marriott Hotel, Texas; March 21-22, 1994.

"Buy-Out and Refinancing of REA Loans: Factors to Consider in Evaluation Analysis," Texas Electric Cooperatives, Inc.; Austin, Texas; December 3, 1993.

"Update on Current Issues -- Texas RECs and PUCT," Texas Electric Cooperatives, Inc.; Austin, Texas; November 15, 1993.

"The Co-Op Power Picture in Texas," TEC's 52nd Annual Meeting; Houston, Texas; July 28, 1992.

"Ratemaking Activities for Rural Electric Cooperatives," TEC's Seminar on Electric Cooperatives; Austin, Texas; October 18, 1991.

"Cost of Service Major Points," TEC Accounting Association Annual Meeting; San Antonio, Texas; April 20, 1990.

"Rate Design for Large Power Service and Options for Marketing and Incentive Rates," TEC Engineering Association; Austin, Texas; September 27, 1989.

"Revenue Requirements and Cost of Service Considerations at the PUC," TEC Engineering Association; Austin, Texas; April 28, 1988.

"Course 495.3 - Rate Issues and Philosophies," 1987 Wisconsin Electric Cooperative Association; Wisconsin Rapids, Wis.; December 1-3, 1987.

"Cost Bases for Incentive Rates Applicable to Industrial Loads," 1987 Conference on Industrial Energy Technology; Houston, Texas; September 16-17, 1987.

"Considerations in Cooperative Consolidations," with Martin Lowery at NRECA's 1987 Accounting and Finance Conference; Lexington, Ky.; September 9, 1987.

"Rates to Attract Attractive Loads," Association of Louisiana Electric Cooperatives, in coordination with AHP Systems, Inc.; Baton Rouge, La.; July 1-2, 1987.

"Rates to Attract Attractive Loads," Wisconsin Electric Cooperative Association in Coordination with AHP Systems, Inc.; Stephens Point, Wis.; February 12, 1987.

"Rate Seminar," Indiana Statewide Association of REC, Inc., (Co-Presenter: David Hedberg); Indianapolis, Ind.; September 25, 1986.

"Cost of Service and Rate Design Issues Affecting Industrial Customers in Retail Rate Proceedings," Public Utility Commission of Texas 1986 Industrial Energy Technology Conference; Houston, Texas; June 1986.

"The Importance of the Impact of Rates," NRECA's Management Services Conference -- Preparing Now to Prevent a Takeover or Sellout; Denver, Colo.; April 17-18, 1986; and New Orleans, La.; May 14-15, 1986.

"Energy Cost for Industrial Customers," (Co-Author: M.K. Moore) ACEC Research & Management Foundation's Industrial Energy Management Forum; Tempe, Ariz., March 26, 1986.

"Analysis of Financial and Operating Ratios," REA National Conference; San Antonio, Texas; July 10, 1985.

"Coordination of Wholesale/Retail Rate Design for Effective Marketing Strategy," NRECA's National Marketing Conference; Kansas City, Mo., June 5, 1985.

"Development of a Rate Analysis," NRECA Management Quarterly; Washington, D.C.; Volume 24, No. 3; Summer 1983.

"Cost Allocation Considerations for Rural Distribution Systems," NARUC Biennial Regulatory Information Conference; Columbus, Ohio; October 19, 1978.

"Cost Allocation Considerations and Methods for Electric Rate Analysis and Design for Rural Distribution Systems," IEEE Transactions on Industry Application; Volume 1A-13, No. 2; 1977.

"Design of Irrigation Rates Under Load Management Program," (Co-Authors: S.P. Patwardhan and B.E. Smith), presented at IEEE Rural Power Conference; Kansas City, Mo.; May 16, 1977.

"Cost Allocation Considerations and Methods for Electric Rate Analysis and Design for Rural Distribution Systems," IEEE Rural Electric Power Conference; Omaha, Nebr.; April 1975.

"A Financial Forecasting Model for Rural Electric Distribution Systems," IEEE PES Summer Power Meeting and Energy Resources Conference; Anaheim, Calif.; July 1974.

"Transmission Substation Control Using On-Site Computer Directed Simulation and Closed Loop Control," (Co-Author: H.E. Michel).

"The Development of Design Objectives for Electric Utility Rate Schedules," Master's Thesis; University of Oklahoma, Norman; 1969.

EXHIBIT CNS-2

Rating Methodology

Moody's Global Corporate Finance

December 2009

U.S. Electric Generation & Transmission Cooperatives

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Summary

This rating methodology explains Moody's approach to assessing credit risk in the U.S. electric generation & transmission cooperative sector (G&T co-ops). It replaces the U.S. Electric Generation & Transmission Cooperatives rating methodology that was published in May 2006. While based on the same core principles as the May 2006 methodology, this updated framework incorporates refinements that better reflect the more recent challenges facing G&T co-ops and the way Moody's applies its industry methodologies.

The goal of this report is to help issuers, investors and other interested market participants understand how Moody's assesses credit risk for companies in the U.S. G&T cooperative industry, and to explain how key quantitative and qualitative risk factors map to specific rating outcomes. Cooperative structures in other global industrial sectors may be subject to a number of other considerations and are not intended to be covered by this rating methodology. Our objective is for users to be able to estimate in most cases, within two alpha-numeric rating notches, the likely senior most credit rating for a U.S. electric generation & transmission cooperative.

Moody's analysis of U.S. Electric G&T co-ops focuses on five key rating factors that are considered central to assigning ratings in this sector. The five rating factors encompass 14 elements (or sub-factors), each of which maps to specific letter ratings (see Appendix A). The number of sub-factors is reduced from 22 previously, largely reflecting a combination of several factors that were determined to be somewhat duplicative and to further simplify the rating methodology. The five key factors, which will be detailed in this report, are as follows:

1) Long-Term Wholesale Power Supply Contracts/Regulatory Status

2) Rate Flexibility

3) Member Profile

4) Financial Metrics

5) Size

Moody's Investors Service

In appendix B we have included a detailed rating grid for the 17 G&T co-ops included in this methodology. For each G&T co-op, the grid maps the key rating factors and sub-factors and shows the indicated alpha-numeric rating that is calculated from the overall combination of factors. We also include in appendix C discussions of "outliers" – G&T co-ops whose rating for a specific sub-factor differs by two or more broad rating categories from the actual rating, as G&T co-ops will not always map consistently to their overall rating on every sub-factor.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the U.S. G&T co-op sector. The grid provides summarized guidance on the factors that Moody's believes are most important in assigning ratings to G&T co-ops. The grid is a summary rather than an exhaustive representation of every rating consideration and does not fit every business model equally well. In addition, many of our sub-factor mappings utilize historical financial or statistical data to illustrate the grid; however, our ratings also consider future expectations. Accordingly, the grid indicated rating is not expected to always match the actual rating of each G&T co-op. The text of the rating methodology provides insights on the key rating considerations that are not represented in the grid, as well as the circumstances in which the rating effect for a factor might be significantly different from the weight indicated in the grid.

Readers should also note that this rating methodology does not attempt to provide an exhaustive list of every factor that can be relevant to G&T co-op ratings. For example, our analysis covers factors that are common across all industries (such as debt leverage, liquidity, ownership, and legal structure) as well as factors that can be meaningful on a company specific basis (such as litigation, environmental or carbon exposure, capital expenditure needs, and customer and generation supply diversity).

This publication includes the following sections:

- **About the Rated Universe**: overview of the rated G&T co-op universe
- **About this Rating Methodology**: description of our rating methodology, including a detailed explanation of each of the key factors that drive ratings
- **Assumptions and Limitations**: Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

In addition to appendices A, B, and C, we also provide a brief industry overview (Appendix D) and a discussion of key rating issues for the G&T co-op sector over the intermediate term (Appendix E).

About The Rated Universe

An electric generation & transmission cooperative is a not-for-profit rural electric system whose primary function is to provide electric power on a wholesale basis to its owners. These owners are comprised of a group of distribution co-ops and in some instances may also include small G&T co-ops. Each distribution cooperative sells power on a retail basis to its customers, who are the members that own the distribution co-op.

Moody's currently rates 17 U.S. electric G&T cooperatives, included among which are many of the larger G&T co-ops and a growing number of the medium to smaller-sized ones. The group of 17 has approximately $22.1 billion of debt outstanding and collectively owns/controls or purchases approximately 41,000 megawatts of electric generation capacity. All of these issuers are currently rated investment grade and all except one pending review for possible downgrade and three negative rating outlooks currently carry a stable rating outlook. The G&T cooperatives currently occupy the investment-grade, single-A to high-Baa range.

The credit profile of G&T co-ops on the whole has been stable. Over the past three years, we have added six G&T cooperatives to our rated universe, including Great River Energy, Golden Spread Electric Cooperative, Minnkota Power Cooperative, South Mississippi Power, Big Rivers Electric Corp., and PowerSouth Energy Cooperative, bringing the total to 17 in all. In addition to the six new ratings assigned, three issuers were downgraded, none were upgraded, and three rating outlooks were changed to negative from stable. We also assigned three new commercial paper program ratings for Basin Electric Power Cooperative (Prime-1), Arkansas Electric Cooperative (Prime-1) and Chugach Electric Association (Prime-2). Chugach Electric Association's senior unsecured long-term rating was downgraded in December 2008 to A3 from A2 in conjunction with assigning a Prime-2 short-term rating to its commercial paper program. The downgrade

U.S. Electric Generation & Transmission Cooperatives

reflected concerns about potential loss of wholesale revenue, re-financing risk, external financing of higher capital expenditures, and the potential need for higher rates, which are subject to Alaska regulatory jurisdiction. In April 2009, Hoosier Energy's senior secured rating was downgraded to Baa1 from A3 and kept on review for possible further downgrade, primarily due to concerns about ongoing litigation with John Hancock Life Insurance Company related to an existing leveraged lease transaction and the potential effects on its liquidity. In September 2009, Oglethorpe Power's rating outlook was changed to negative from stable, primarily reflecting concerns about the costs associated with its plans to partner with others in constructing a new nuclear plant, among other factors. In October 2009, Dairyland Power's A2 Issuer Rating was downgraded to A3 and its rating outlook is negative. The downgrade primarily reflected concerns about weak metrics compared to its prior rating level and the negative outlook captures ongoing concerns that soft market power rates in the Midwest may delay potential opportunities for Dairyland to take advantage of its strong baseload capacity profile by engaging in third party sales. On November 11, 2009, Buckeye Power's rating outlook was changed to negative from stable primarily reflecting the recent weakening of its credit metrics but also our concern as to how long it may take for improvement in the metrics to materialize given the softness in the economy of the region and lower than expected power prices for excess energy sales.

Meanwhile, we note that G&T co-ops have conservatively managed their businesses during the past three years by:

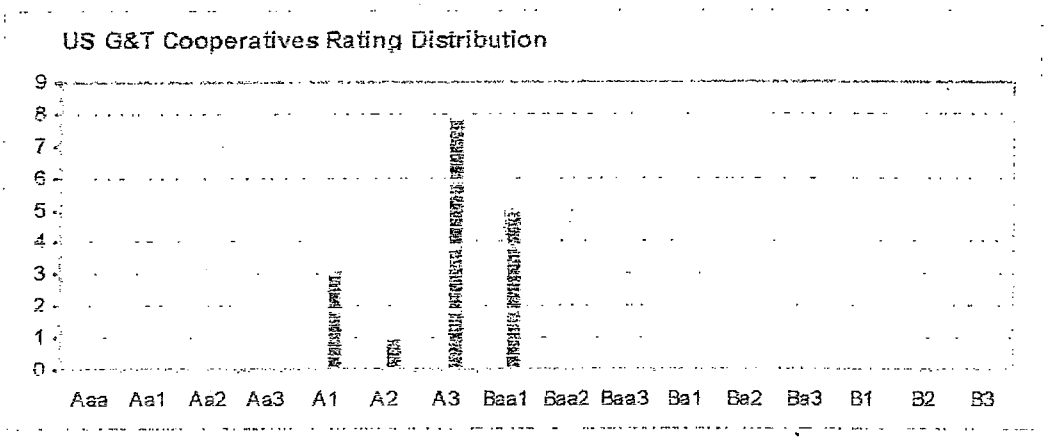
- *using long term supply planning to meet increasing demands for power from their member co-ops,*
- tightly controlling operating costs,
- increasing rates when necessary, and
- carefully attending to liquidity.

The following table illustrates the distribution of ratings in the U.S. G&T cooperative sector.

Rated Issuers

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Arkansas Electric Cooperative	A2 (a)	P-1	Stable	644 (e)
Associated Electric Cooperative	A1		Stable	1,478
Basin Electric Power Cooperative	A1	P-1	Stable	2,287
Big Rivers Electric Corp.	(P) Baa1		Stable	1,039 (f)
Buckeye Power Inc.	A1		Negative	1,318
Chugach Electric Association	A3 (b)	P-2	Stable	346
Dairyland Power Cooperative	A3 (c)		Negative	973
Georgia Transmission	A3	P-2	Stable	1,560
Golden Spread Electric Cooperative	A3 (c)		Stable	161
Great River Energy	A3		Stable	2,362
Hoosier Electric Power	Baa1		RUR ↓	1,138
Minnkota Power Cooperative	Baa1 (c)		Stable	258
Oglethorpe Power Corp.	A3	P-2	Negative	4,127
Old Dominion Electric Cooperative	A3		Stable	783
PowerSouth	Baa1 (c)		Stable	1,411
South Mississippi Electric Power Association	A3		Stable	758
Tri-State G&T Association	Baa1		Stable	1,880
Total Unadjusted Debt of Rated G&T Co-ops				**22,524**

Notes:
[1] Ratings are senior secured unless otherwise noted
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating
(d) As of June 30, 2009, unless otherwise indicated
(e) As of July 31, 2009
(f) As of December 31, 2008



About This Rating Methodology

Moody's U.S. electric G&T cooperative rating methodology consists of the six sections listed below.

1) Identification of the Key Rating Factors

The grid in this methodology focuses on five broad rating factors, further broken down into 14 rating sub-factors and their weightings.

Rating Factor/Sub-Factor Weighting - U.S. Electric G&T Cooperatives

Rating Factor	Weighting	Rating Sub-Factor	Sub-Factor Weighting
Wholesale Power Contracts and Regulatory Status	20%	% Member Load Served and Regulatory Status	20%
Rate Flexibility	20%	Board Involvement / Rate Adjustment Mechanism	5%
		Purchased Power / Sales (%)	5%
		New Build Capex (% of Net PP&E)	5%
		Rate Shock Exposure	5%
Member / Owner Profile	10%	Residential Sales / Total Sales	5%
		Members' Consolidated Equity / Capitalization	5%
3-Year Average G&T Financial Metrics	40%	TIER	5%
		DSC	5%
		FFO / Debt	10%
		FFO / Interest	10%
		Equity / Capitalization	10%
G&T Size	10%	MWh Sales	5%
		Net PP&E	5%
Total	100%		100%

These factors are critical to the analysis of U.S. Electric G&T cooperatives and, in most instances, can be benchmarked across the sector. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2) Measurement of Key Rating Factors

We explain the measurements we use to assess performance on each of the rating factors and sub-factors. We explain the rationale for using specific rating factors and provide insights on the way these are applied in the rating decision process. Many of the sub-factors are found in or derived from the financial statements of the G&T co-ops and those of their members, while others are calculated or derived using data gathered from various sources, and observations and estimates by Moody's analysts.

Moody's ratings are forward looking and incorporate our expectations of future financial and operating performance. We use both historical and projected financial results in the rating process; however, this document makes use only of historic data, and does so solely for illustrative purposes. Historical operating results help us understand the pattern of a company's performance and how it compares to its peers. Historical data also assists us in, among other things, looking through the earnings volatility that can sometimes occur during a given year and evaluating whether projected future results are realistic.

This rating methodology uses historical data in most instances based on information as of the latest fiscal year end; however, the sub-factors for financial metrics use three-year averages for the last three fiscal years.

All of the quantitative credit metric measures comprising the sub-factors in Factor 4 incorporate Moody's standard adjustments to the income statement, statement of cash flows, and balance sheet and include adjustments for certain off-balance sheet financings and certain other reclassifications in the income statement and statement of cash flows.

3) Mapping Factors to Rating Categories

After identifying the measurement criteria for each rating sub-factor, we provide a chart that maps the rating sub-factors to specific alpha rating categories (Aaa, Aa, A, Baa, Ba, or B). In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of FFO/Interest is generally acceptable for an A credit versus a Baa credit, etc.

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

In this section (Appendix B), we provide a table showing how each company maps within the specific rating sub-factors. The weighted average of the sub-factor ratings produces a grid indicated rating for each broad factor. We also highlight companies (Appendix C) whose grid indicated performance on a specific factor or sub-factor is higher or lower by two or more broad rating categories from the actual rating. A company whose performance is two or more broad rating categories higher than its actual rating is deemed a positive outlier for that factor. A company whose performance is two or more broad rating categories below is deemed a negative outlier. We also discuss the general reasons for such outliers within a given factor or sub-factor.

5) Discussion of Assumptions, Limitations and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings as well as limitations and key assumptions that pertain to the overall rating methodology.

6) Determining the Overall Grid-Indicated Rating

To determine the overall grid-indicated rating, the indicated rating category for each sub-factor is converted into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-average factor score. The composite weighted-average factor score is then mapped back to an alpha-numeric rating based on the ranges in the grid below.

Composite Rating

Indicated Rating	Aggregate Weighted Factor Score
Aaa	$0.0 \leq x < 1.5$
Aa1	$1.5 \leq x < 2.5$
Aa2	$2.5 \leq x < 3.5$
Aa3	$3.5 \leq x < 4.5$
A1	$4.5 \leq x < 5.5$
A2	$5.5 \leq x < 6.5$
A3	$6.5 \leq x < 7.5$
Baa1	$7.5 \leq x < 8.5$
Baa2	$8.5 \leq x < 9.5$
Baa3	$9.5 \leq x < 10.5$
Ba1	$10.5 \leq x < 11.5$
Ba2	$11.5 \leq x < 12.5$
Ba3	$12.5 \leq x < 13.5$
B1	$13.5 \leq x < 14.5$
B2	$14.5 \leq x \leq 15.0$

For example, an issuer with a composite weighted factor score of 8.2 would have a Baa1 grid-indicated rating. We use a similar procedure to derive the grid-indicated ratings in the tables embedded in the discussion of each of the five broad rating factors.

The Key Rating Factors

Moody's analysis of U.S. G&T co-ops focuses on five broad rating factors:

- Long-Term Wholesale Power Supply Contracts/Regulatory Status
- Rate Flexibility
- Member Profile
- Financial Metrics
- Size

Factor 1: Long-Term Wholesale Power Supply Contracts/Regulatory Status

Why it Matters

Against a backdrop of significant spending for capital projects, volatile fuel costs and looming carbon legislation and related costs, the strength of the wholesale power contracts and the predictable revenue stream they provide for G&T co-ops remains a primary source of credit support. Because the prevalence of rate autonomy is similarly an integral credit factor linked to costs tied to the wholesale power contract, we have *combined regulatory status of the G&T and its distribution member/owners, previously considered in Factors 2* and 3, respectively, into Factor 1. In doing so, we also increased the weighting for Factor 1 to 20% from 15% previously.

Long term wholesale power supply contracts between G&T co-ops and their members provide G&T co-ops with a high degree of assurance that costs and capital investment can be recovered from rates charged to customers. These contracts typically require the member co-ops to purchase all or virtually all of their supply requirements from the G&T co-op and generally stipulate that co-op members must pay their pro-rata portion of all of the G&T co-op's fixed and variable costs related to the generation, procurement and transmission of their respective energy needs.

G&T co-ops have more flexibility to increase rates in response to rising costs as regulatory approval is typically not required. The regulatory status/relationship with regulators is important because G&T co-ops that operate *in states that have some form of regulatory authority over their rate setting activities may have more difficulty* raising rates compared to peers who are not directly subject to regulatory control. Assessing a member/owner's regulatory status is also important because some are subject to rate regulation, in which case the member may be denied approval for a large rate increase, making it difficult to comply with its contractual obligations to the G&T co-op.

An unsupportive regulatory jurisdiction is a credit negative and leaves co-ops with less flexibility to raise rates if needed. In contrast, absence of regulatory control over the rate setting process is a credit positive. Most co-ops are not subject to rate regulation, and set the rates they charge their members after careful consideration of their underlying cost structure and expected demand for power. They calculate what level of revenues would be required in order to meet operating costs, minimum required interest, and debt service coverage covenants in the RUS mortgage and/or other debt indentures, while also providing some cushion of revenue and equity to protect against adverse events such as sudden increases in costs or operating difficulties with key generating plants.

How We Measure It for the Grid

Based on data that can be derived from various sources, we calculate the percentage of member power supply needs served under the long-term wholesale power contract(s), with consideration as to whether the contracts are all requirements or substantially all requirements in nature. An assessment of the wholesale power contract allows us to identify whether the member co-ops are required to purchase all or virtually all of their supply requirements from the G&T co-op. For G&T co-ops who are not subject to rate regulation, the indicated rating for Factor 1 can range from Aaa to B and is largely determined by the overall percentage of member sales made under the wholesale power contracts. To receive the highest score of Aaa requires a legislative statute that precludes regulatory intervention in any future rate setting process. There are no such instances that currently apply within the rated universe.

We understand that there are currently 10 states that have full regulatory jurisdiction over the level of rates that co-ops can charge their members. These states are: Arizona, Arkansas, Alaska, Kansas, Kentucky, Louisiana, Maine, Maryland, Vermont, and Wyoming. There are a few other states including Indiana, New Mexico, and Michigan where state commissions have partial jurisdiction over G&T co-ops. Even if 100% of members' needs are met through sales under the wholesale power contracts, G&T co-ops conducting business in any of the aforementioned states would receive an indicated rating for Factor 1 of A at best. Where precisely the few rate-regulated G&Ts score within the range of A to B depends not only on the

percentage of members' needs met through sales under the wholesale power contract, but also on our consideration of how supportive of credit quality the regulatory practices are and our understanding of the type of working relationships that prevail between the co-ops and the regulators.

Factor 1: Long-Term Wholesale Power Supply Contracts and Regulatory Status (20%)

Percentage of Member Load Served under Wholesale Power Contracts and Regulatory Status	100% and G&T and its Distribution Member/Owner Cooperatives are Not Rate Regulated by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process	100% and G&T is Not Rate Regulated by State Commission; No legislative statute to preclude regulatory intervention in the future G&T rate setting process; Some Distribution Member/Owner Cooperatives May Be Subject to Rate Regulation by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 80% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory Relationships	< 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory Relationships	< 60% and/or G&T is Rate Regulated by State Commission; Most Distribution Member/Owner Cooperatives are Rate Regulated By State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships

Factor 2: Rate Flexibility

Why it Matters

Prices for fuels used to generate electricity are unregulated in the U.S. and have been subject to dramatic fluctuation over the last couple of years. G&T co-ops need the flexibility to raise rates in order to cover sharply higher prices for fuels, in addition to rising operating costs, and costs associated with existing mandated environmental requirements and those inevitably forthcoming related to carbon emissions along with any capital investment associated with construction of new plants (especially nuclear powered), among other factors.

We note that the number of sub-factors in Factor 2 have been reduced to four from six previously, as regulatory status was combined into Factor 1 and rate competitiveness was combined into Rate Shock Exposure. In doing so, each of the remaining four sub-factors in Factor 2 have been assigned a 5% weighting.

Board Involvement/Rate Adjustment Mechanisms: The extent to which a G&T co-op can ensure timely and full recovery of its costs and investments will have an integral effect on its overall financial performance and thus its creditworthiness. Each G&T coop's board of directors has a fiduciary responsibility to approve, or, where rate regulation applies, to seek regulatory approval of rates that ensure compliance with the financial covenants associated with debt indentures. To the extent that unexpected events arise, causing concerns about ability to comply with covenants, the board should be expected to move quickly to adjust rates upward when needed. Also, variable cost adjustment mechanisms provide for more automatic changes in rates when costs change and increase the speed with which rates can be increased when costs increase. The extent to which variable cost adjustment mechanisms are available is especially important where regulatory jurisdiction applies to a G&T co-op. The existence of variable cost adjustment mechanisms is a credit strength, especially

when rate adjustments can be implemented at frequent intervals. Such mechanisms mitigate liquidity pressures that might otherwise arise when the cost of fuels exceeds rates in effect at that time.

Degree of Reliance on Purchased Power: Most of the power supply needs of G&T co-op members are met from generating plants owned by the G&T coops. Some G&Ts rely on market purchases of power to meet a portion of the member needs because their owned resources are insufficient, uneconomic, or periodically unavailable.

Assessing the degree of reliance on purchased power to meet members' demand and the rationale behind that strategy is important because G&Ts who purchase large amounts of power from the market to meet member demands may face increased price volatility for one of their largest costs. Relying on such a strategy also heightens the importance of liquidity, risk management policies and procedures, and counterparty credit assessment.

New Build Exposure Relative to Existing Asset Base: This factor is important because G&T co-ops largely finance capital investment with debt and rely upon rate increases to service the debt. When construction is delayed or runs above budget, the rate increases needed to cover the increased costs could lead to member resistance.

Potential for Rate Shock Exposure: In many respects, the potential for rate shock exposure is linked to rate competitiveness, so we have combined our consideration of rate competitiveness into this sub-factor as part of this updated methodology. Assessing the potential for rate shock exposure is important because a large rate increase can lead to member resistance even when the new higher level of rates is still competitive with other providers of power in the region. If the G&T co-op's rates are noticeably higher than other providers in its geographic area, member unrest could lead to contract challenges or possible withdrawal from the co-op.

How We Measure It for the Grid

Board Involvement/Rate Adjustment Mechanisms: The timing and extent to which a G&T co-op can increase rates is impacted by the activity of its board of directors and a number of rate adjustment mechanisms.

First we assess how active a board has been from a historical perspective with respect to approving or seeking regulatory approval of rate increases and consider the extent to which past behavior might change. To the extent that unexpected events arise, causing concerns about ability to comply with covenants, we believe the board should be expected to move quickly to adjust rates upward when needed. Those G&T co-ops whose boards of directors are exceptionally proactive in adjusting rates as necessary and who benefit from legislative statute that would preclude regulatory intervention in the future rate setting process would most likely receive the highest indicated ratings. In contrast, G&T co-ops with less active or even inactive boards of directors and who otherwise face uncertainty surrounding the extent and timing of cost recovery would receive much lower indicated ratings for this sub-factor.

With respect to situations where variable cost adjustment mechanisms apply, rates that can automatically adjust to fuel and/or purchased power cost increases without requiring action by the Board or regulators are viewed more favorably and generally result in a higher indicated rating for this sub-factor. In instances where recovery of variable cost increases is deferred, we consider the time period over which recovery occurs, with shorter periods obviously being better from a liquidity and credit quality standpoint.

Degree of Reliance on Purchased Power: To measure the degree to which a G&T relies on purchased power in conducting its business, we divide the amount of megawatt hours it purchases during the most recent fiscal year by the total megawatt hours of energy it sells. This data can usually be found in the G&T co-op's latest annual report and/or other published data sources. In those instances where a G&T co-op relies on purchased power to meet less than 40% of its energy requirements during a given fiscal year, the indicated rating for this sub-factor would be at least Baa and improve gradually as the percentage declines according to the Factor 2 table descriptions. Conversely, where the dependence on purchased power exceeds the 40% level, then the indicated rating would be Ba or lower according to the Factor 2 table descriptions.

New Build Exposure Relative to Existing Asset Base: To measure this sub-factor, Moody's divides the estimated future capital expenditures for a particular G&T co-op over the next five years by the net property, plant, and equipment report for the latest fiscal year end. The lower the resulting percentage from this calculation is, the better the indicated rating for the sub-factor will likely be, as the G&T will likely face less need to issue debt and increase rates to cover the higher financing costs.

Potential for Rate Shock Exposure: To measure the potential for rate shock exposure, Moody's continues to look at the extent to which a G&T relies on purchased power to meet its energy demand during the latest fiscal year and its new build exposure. A lower percentage in both instances is generally viewed more favorably under the methodology. In addition, we have expanded our measurement criteria for this sub-factor to also consider the G&T's reliance on coal and other carbon emitting generating resources. Those G&Ts with a high reliance on such resources will be scored lower on this sub-factor due to their vulnerability to potential carbon legislation and accompanying carbon costs.

Cost competitive G&T co-ops have greater flexibility to raise rates to offset cost increases or to build additional equity and would therefore be more likely to receive a higher indicated rating for this sub-factor than those G&Ts who are competitively challenged. Favorable characteristics include low or improving cost structure, lower wholesale prices versus peers, and low distribution member rates versus competitors in the region. Moody's also assesses a G&T co-op's prospects to realize future rate increases in order to offset increasing costs, as compared with others in the region although consistent rate data is often not publicly available. Nonetheless, Moody's seeks whatever public information is available, as well as confidential information on a company by company basis.

Factor 2 - Rate Flexibility (20%)

							Weight
Assess Board Involvement in Setting Rates / Variable Cost Adjustment Mechanisms	Exceptionally proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; Legislative statute to preclude regulatory intervention in the future rate setting process	Proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; No legislative statute to preclude regulatory intervention in the future rate setting process	Active board in support of timely rate filings; possibility for regulatory intervention in the rate setting process in certain instances; frequent fuel cost adjustment capability in place under regulatory practice; timely recovery of any deferrals	Reasonably active board in support of timely rate filings; annual fuel cost adjustment capability in place under regulatory practice; reasonably timely recovery of any deferrals	Inactive board; limited, if any ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	5%
Purchased Power/Total MWh Sales (%)	x < 5%	5% ≤ x < 20%	20% ≤ x < 30%	30% ≤ x < 40%	40% ≤ x < 60%	x ≥ 60%	5%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	x < 5%	5% ≤ x < 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x ≤ 120%	x > 120%	5%
Potential for Rate Shock Exposure	Better rates than all others in the region on a consistent basis; Extremely low (e.g. Less than 10% reliance on purchased power and less than 10% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 0-20% of generation from carbon fuels	Much better rates than most in the region on a consistent basis; Very low (e.g. less than 20% reliance on purchased power and less than 25% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 20-40% of generation from carbon fuels	Better rates than most in the region on a consistent basis; Low (e.g. less than 30% reliance on purchased power and/or less than 50% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 40-55% of generation from carbon fuels	Better rates than some and worse rates than some in the region on a consistent basis; Moderate (e.g. less than 40% reliance on purchased power and/or less than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 55-70% of generation from carbon fuels	Worse rates than most in the region on a consistent basis; High (e.g. greater than 40% reliance on purchased power or greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 70-85% of generation from carbon fuels	Worse rates than all in the region on a consistent basis; Very high (e.g. greater than 40% reliance on purchased power and greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 85-100% of generation from carbon fuels	5%

Factor 3: Member Profile

Why it Matters

Assessing the member profile of a G&T co-op is important because the members who own the G&T co-op are also its primary source of cash flow. Similar to the way we would assess the counterparty credit risk for an IOU that sells sizable amounts of power to another entity, or buys significant amounts of power from a wholesale power producer, we are concerned about the overall creditworthiness of the members. Although we still seek information about the members' expected consolidated demand growth and their consolidated

assets, to further simplify this methodology, these two sub-factors previously included in the May 2006 methodology are not specifically incorporated into this update. The following two sub-factors, which are weighted at 5% each, continue to provide good insight into the members' creditworthiness and ability to meet obligations to the G&T co-op under the long-term wholesale power contract.

Residential Sales as a Percentage of Total Sales: The diversity of the members' retail customer mix is important in our analysis of G&T co-ops because substantial reliance upon any single customer or a small number of customers (such as large industrial customers) tends to be associated with greater variability of revenue. Members who own the G&T co-ops tend to serve large residential customer bases, with a majority of energy being sold to such customers, although some sales may be to more volatile industrial and commercial customers. A higher percentage of sales to residential customers is favorable because such sales are generally more stable and predictable.

Members Consolidated Equity to Capitalization: The financial condition of the member/owners, as measured in part by the members' consolidated equity to capitalization, is important because it affects their ability to perform under the wholesale power contracts that members have with their G&T co-op. For the most part, distribution co-ops carry less business and financial risk than G&T co-ops. The difference in the financial strength is largely attributable to the fact that the RUS has historically set tighter financial covenants for the distribution co-ops than for the G&T co-ops. In addition, the distribution co-ops are far less capital intensive than G&T co-ops who own generation assets. Distribution co-ops typically maintain higher levels of equity to total capitalization and stronger interest coverage ratios than G&T co-ops.

How We Measure It for the Grid

Residential Sales as a Percentage of Total Sales: To measure this sub-factor, we first generally aggregate the individual residential energy sales and total energy sales for each member/owner of a particular G&T co-op in the latest fiscal year. This information is generally available through requests made to the G&T because their members provide this data to them. The aggregate residential energy sales level is then divided by the aggregate total energy sales level to derive the aggregate percentage for the year. Under the Methodology, a higher percentage of more stable and predictable residential sales is viewed more favorably than a concentration of sales to large commercial and/or industrial customers.

Members Consolidated Equity to Capitalization: This sub-factor is measured by simply aggregating each member's total equity and debt as reported for the latest fiscal year end. The aggregate totals are then used to divide total members' debt by the sum of total members' debt plus equity. Members generally file financial statements with the RUS or otherwise make such statements available to the G&T that they have an ownership interest in. Most of the G&T co-ops that are covered by the methodology fall into the Baa or A category with consolidated member equity to capitalization in the range of 25% to 50%.

Factor 3 - Member/Owner Profile (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Residential Sales/ Total Sales (%)	x ≥ 80%	75% ≤ x < 80%	50% ≤ x < 75%	40% ≤ x < 50%	20% ≤ x < 40%	x < 20%	5%
Members' Consolidated Equity/Capitalization (%)	x ≥ 65%	55% ≤ x < 65%	50% ≤ x < 55%	25% ≤ x < 50%	20% ≤ x < 25%	x < 20%	5%

Factor 4: G&T Financial Metrics

Why it Matters

Financial strength is an important indicator of a G&T co-op's ability to meet its obligations, including debt service. Moody's considers historical coverage ratios and also places a significant emphasis on the expected trend for coverage metrics when assessing the credit risk of G&T co-ops. In the interest of reducing the number of sub-factors and simplifying this methodology, we dropped the net operating margin metric from

Factor 4 as part of the update of this methodology since the net margin component of the coverage calculations already captures the operating profit. In doing so, we also adjusted the weighting of the remaining five sub-factors in Factor 4 to retain the overall 40% weighting for financial metrics. Nevertheless, we continue to highlight that while some G&T co-ops have large investment portfolios that considerably augment the bottom line, we consider it important that the G&T co-op be profitable on an operating basis. G&T co-ops that *rely extensively on profits from investment portfolios and diversified operations to compensate for negative* G&T operating margins are still viewed negatively.

Scores under Factor 4 may be higher or lower than what might be produced based on historical results, depending on our view of expected future financial performance.

Times Interest Earned Ratio (TIER) and Debt Service Coverage Ratio (DSC): These two ratios are important because they have governed RUS loan documentation for many years. In addition to TIER and DSC, Moody's also looks at margins for interest (MFI) as defined in certain indentures.

Funds from Operations Coverage of Interest (FFO/Interest) and FFO/Debt: The FFO/Interest and FFO/Debt metrics are important because they provide insight regarding the amount and quality of a G&T co-op's cash flow and its ability to service its debt.

Equity/Total Adjusted Capitalization: Moody's evaluates the G&T co-op's equity as a percentage of total adjusted capitalization to see how much flexibility there is in the balance sheet to absorb unexpected events. When measuring the level of equity cushion, G&T co-ops and the RUS have tended to rely on equity expressed as a percentage of total assets. However, Moody's and many investors prefer to measure equity as a percentage of total capitalization, because it facilitates comparison with IOU capital structures.

How We Measure It for the Grid

See Moody's Ratings Methodology: Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations - Part 1, July 2005. The ratios used as a basis for this methodology are three year averages of calculations using the latest three fiscal year end statements, including standard adjustments. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios. The ranges for each of the five metrics that would correspond to a particular indicated rating category appear in the table at the bottom of this section. The individual metric definitions are as follows:

TIER:

(Net margins, as represented by net profit after tax before unusual items + Interest + Income Tax) / Interest

DSCR:

(Net margins, as represented by net profit after tax before unusual items + Interest + Depreciation & Amortization) / (Interest + Principal Payment)

FFO / Interest:

(Funds from operations + Interest expense)/ Interest expense

FFO / Debt:

Funds from operations / (Short Term Debt + Long Term Debt, gross)

Equity / Total Capitalization:

(Deferred Taxes + Minority or Non-controlling Interest + Book Equity) / (Short Term Debt + Long Term Debt, gross + Deferred Taxes + Minority or Non-controlling Interest + Book Equity)

Factor 4 - 3-Year Average G&T Financial Metrics (40%)

TIER	x ≥ 1.6x	1.4x ≤ x < 1.6x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
DSC	x ≥ 1.9x	1.4x ≤ x < 1.9x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
FFO/Debt	x ≥ 15%	10% ≤ x < 15%	6% ≤ x < 10%	3% ≤ x < 6%	2% ≤ x < 3%	x < 2%	10%
FFO/Interest	x ≥ 3.25x	2.5x ≤ x < 3.25x	2.0x ≤ x < 2.5x	1.5x ≤ x < 2.0x	1.2x ≤ x < 1.5x	x < 1.2x	10%
Equity/Total Capitalization	x ≥ 50%	35% ≤ x < 50%	20% ≤ x < 35%	5% ≤ x < 20%	3% ≤ x < 5%	x < 3%	10%

Factor 5: G&T Size

Why it Matters

Size, together with Factor 3, Member Profile, has the lowest weighting of the five key factors because it tends to be less important for entities, such as G&T coops, that are subject to limited competition. As part of the update to this methodology, we have eliminated two sub-factors from Factor 5 (i.e. megawatts owned/purchased and revenues) because we found that they were somewhat duplicative and wanted to further simplify the methodology. Nevertheless, we still find that size, as measured by the following two sub-factors, which are weighted at 5% each, does matter.

Megawatt hour sales: This sub-factor is important because it is an indicator for economies of scale (i.e., a G&T co-op is better off if it can spread its fixed costs over a larger number of megawatt hours of electricity, thereby increasing its price competitiveness).

Net Property, Plant, and Equipment: This sub-factor is important because G&T co-ops can benefit from having a larger pool of assets and a more diverse source of fuels to run the generation assets it owns. A G&T co-op that has its assets concentrated in one generating plant could be subject to extreme cost pressures to the extent that it has to buy power on the open market due to an extended outage at its sole generating plant. Similarly, overdependence on one particular fuel source could materially raise costs during a period of prolonged price increases for that commodity.

How We Measure It for the Grid

We identify the amount of megawatt hour sales and net property, plant, and equipment data primarily from the G&T co-op's latest annual report. See the Factor 5 table below for the ranges that would apply for a particular indicated rating for the two sub-factors in Factor 5.

Factor 5 - G&T Size (10%)

	Aaa	Aa	A	Baa	Ba	B	Weighting
Megawatt hour sales (Millions of MWhs)	*x ≥ 50*	*20 ≤ x < 50*	*11 ≤ x < 20*	*5 ≤ x < 11*	*3 ≤ x < 5*	*x < 3*	5%
Net PP&E ($ in Billions)	x ≥ 5	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < 0.3	5%

Rating Methodology Assumptions and Limitations, and Other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The five rating factors in the grid do not constitute an exhaustive treatment of all the considerations that are important for ratings of

G&T co-ops. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we cannot publish. In other cases, we estimate future results based upon past performance, industry trends, demand and price outlook, peer actions and other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

In choosing the metrics for this rating methodology grid, we did not include certain important factors that are common to all companies in any industry, such as the quality and experience of management, assessments of corporate governance and quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and ranking them by rating category in a grid would, in some cases, suggest too much precision in the relative ranking of particular issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental obligations, nuclear decommissioning trust obligations, industrial customer concentrations, financial controls, and the political and economic environment, including possible government interference.

As an example, industrial exposure can vary considerably across the rated universe and this customer class can sometimes be subjected to more cyclicality in terms of energy consumption, which cannot be consistently represented in a simple grid format.

Actual ratings assigned may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, Factors 1 and 2 address long term wholesale power contracts/regulatory status and rate flexibility, respectively; however, there may be instances where the effects of a G&T cooperative's financial metrics will be given greater consideration in an assigned rating than what is indicated by the weighting in the grid.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

The objective of our methodology is for users to be able to estimate in most cases, within two alpha-numeric rating notches, the likely senior most credit rating for a U.S. electric generation & transmission cooperative. For consistency in drawing our conclusions, we rely upon an implied senior secured rating (i.e. the implied senior most rating) for the six G&T cooperatives who have senior secured debt in their respective capital structures but whose current ratings are either senior unsecured Issuer Ratings or whose current ratings apply to a class of debt junior to the senior secured debt. The methodology grid-indicated ratings map to Moody's current assigned or implied senior most ratings as follows (See Appendix B for the details):

Eight cooperatives or 47% have indicated ratings that match the Moody's actual (or implied) senior most rating,

six cooperatives or 35% have indicated ratings within one-notch of Moody's actual (or implied) senior most rating, and

three cooperatives or 18% have an indicated rating within two-notches of Moody's actual (or implied) senior most rating.

APPENDIX A: U. S. Electric G&T Cooperative Methodology Factor Grid

Factor 1: Long-Term Wholesale Power Supply Contracts and Regulatory Status

Percentage of Member Load Served under Wholesale Power Contracts and Regulatory Status	100% and G&T and its Distribution Member/Owner Cooperatives are Not Rate Regulated by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process	100% and G&T is Not Rate Regulated by State Commission; No legislative statute to preclude regulatory intervention in the future G&T rate setting process; Some Distribution Member/Owner Cooperatives May Be Subject to Rate Regulation by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 80% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	> 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory Relationships	< 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory Relationships	< 60% and/or G&T is Rate Regulated by State Commission; Most Distribution Member/Owner Cooperatives are Rate Regulated By State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships	20%

Factor 2: Rate Flexibility

Assess Board Involvement in Setting Rates / Variable Cost Adjustment Mechanisms	Exceptionally proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; Legislative statute to preclude regulatory intervention in the future rate setting process	Proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory intervention in the rate setting process; No legislative statute to preclude regulatory intervention in the future rate setting process	Active board in support of timely rate filings; possibility for regulatory intervention in the rate setting process in certain instances; frequent fuel cost adjustment capability in place under regulatory practice; timely recovery of any deferrals	Reasonably active board in support of timely rate filings; annual fuel cost adjustment capability in place under regulatory practice; reasonably timely recovery of any deferrals	Inactive board; limited, if any ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	5%
Purchased Power/Total MWh Sales (%)	x < 5%	5% ≤ x < 20%	20% ≤ x < 30%	30% ≤ x < 40%	40% ≤ x < 60%	x ≥ 60%	5%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	x < 5%	5% ≤ x < 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x ≤ 120%	x > 120%	5%
Potential for Rate Shock Exposure	Better rates than all others in the region on a consistent basis; Extremely low (e.g. Less than 10% reliance on purchased power and less than 10% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 0-20% of generation from carbon fuels	Much better rates than most in the region on a consistent basis; Very low (e.g. less than 20% reliance on purchased power and less than 25% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 20-40% of generation from carbon fuels	Better rates than most in the region on a consistent basis; Low (e.g. less than 30% reliance on purchased power and/or less than 50% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 40-55% of generation from carbon fuels	Better rates than some and worse rates than some in the region on a consistent basis; Moderate (e.g. less than 40% reliance on purchased power and/or less than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 55-70% of generation from carbon fuels	Worse rates than most in the region on a consistent basis; High (e.g. greater than 40% reliance on purchased power or greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 70-85% of generation from carbon fuels	Worse rates than all in the region on a consistent basis; Very high (e.g. greater than 40% reliance on purchased power and greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 85-100% of generation from carbon fuels	5%

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Factor 3: Member / Owner Profile

Factors	Aaa	Aa	A	Baa	Ba	B	Weight
Residential Sales/Total Sales (%)	x ≥ 80%	75% ≤ x < 80%	50% ≤ x < 75%	40% ≤ x < 50%	20% ≤ x < 40%	x < 20%	5%
Members' Consolidated Equity/Capitalization (%)	x ≥ 65%	55% ≤ x < 65%	50% ≤ x < 55%	25% ≤ x < 50%	20% ≤ x < 25%	x < 20%	5%

Factor 4: 3-Year Average G&T Financial Metrics

Factors	Aaa	Aa	A	Baa	Ba	B	Weight
TIER	x ≥ 1.6x	1.4x ≤ x < 1.6x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
DSC	x ≥ 1.9x	1.4x ≤ x < 1.9x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
FFO/Debt	x ≥ 15%	10% ≤ x < 15%	6% ≤ x < 10%	3% ≤ x < 6%	2% ≤ x < 3%	x < 2%	10%
FFO/Interest	x ≥ 3.25x	2.5x ≤ x < 3.25x	2.0x ≤ x < 2.5x	1.5x ≤ x < 2.0x	1.2x ≤ x < 1.5x	x < 1.2x	10%
Equity/Total Capitalization	x ≥ 50%	35% ≤ x < 50%	20% ≤ x < 35%	5% ≤ x < 20%	3% ≤ x < 5%	x < 3%	10%

Factor 5: G&T Size

Factors	Aaa	Aa	A	Baa	Ba	B	Weight
Megawatt hour sales (Millions of MWhs)	x ≥ 50	20 ≤ x < 50	11 ≤ x < 20	5 ≤ x < 11	3 ≤ x < 5	x < 3	5%
Net PP&E ($ in Billions)	x ≥ 5	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < 0.3	5%

APPENDIX B: Methodology Grid-Indicated Ratings

Issuer Ratings				Factor 1: Wholesale Power Customers / Reg Stat Risk	Factor 2: Rate Flexibility				Factor 3: Various Income Profiles		Factor 4: Selected Average Cap / Financial Metrics					Factor 5: G&T Caps	
	Current Rating [1]	Outlook	Indicated Rating	% Memb. Load Served & Reg Stat	Board Involve/Rate Adj. Mech.	Purch. Pwr / Sales (%)	New Build Capex (% Net PP&E)	Rate Shock	Resid. Sales	Member Consol. Eq / Cap	TIER	DSC	FFO / Debt	FFO / Interest	Eq / Cap	MWh sales	Net PP&E
Factor Weighting				20%	5%	5%	5%	5%	5%	5%	5%	5%	10%	10%	10%	5%	5%
Arkansas Electric	A2 (a)	Stable	A3	Baa	A	Aa	Baa	Ba	A	Baa	A	Baa	A	Aa	Aa	A	Baa
Associated Electric	A1	Stable	A2	Aa	Aa	Aa	Baa	Ba	A	A	A	A	A	A	Baa	Aa	A
Basin Electric Power	A1	Stable	A1	Aa	Aa	Aa	B	Ba	Ba	Baa	Aaa	Aa	Aa	Aa	A	A	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	Baa2	Aa	Baa	B	A	B	B	Baa	Aa	Aa	Baa	Baa	B	Baa	Baa
Buckeye Power	A1	Negative	A1	Aa	Aa	Aa	A	B	A	A	A	A	A	Aa	A	Baa	A
Chugach Electric Assoc.	A3 (b)	Stable	A3	Baa	A	Aa	Ba	B	A	Baa	A	Aa	Aa	Aa	A	B	Baa
Dairyland Power	A3 (c)	Negative	Baa1	Aa	Aa	Aa	A	B	A	Baa	Ba	Ba	Baa	Baa	Baa	Baa	Baa
Georgia Transmission	A3	Stable	A2	Aa	Aa	Aa	Baa	Aa	A	Baa	Baa	Ba	Baa	Baa	Baa	Aa	A
Golden Spread Electric	A3 (c)	Stable	A2	A	Aa	B	Ba	B	A	Baa	Aaa	Aaa	Aaa	Aaa	Aaa	Baa	B
Great River Energy	A3	Stable	A3	A	Aa	Baa	Ba	B	A	Baa	A	Baa	A	A	Baa	A	Aa
Hoosier Electric Power	Baa1	RUR ↓	A2	Aa	Baa	A	Baa	B	A	Aa	A	A	A	Aa	Baa	Baa	Baa
Minnkota Power	Baa1 (c)	Stable	A3	Aa	Aa	A	Ba	B	A	Baa	Baa	Baa	Baa	A	Aa	Ba	B
Oglethorpe Power Corp.	A3	Negative	Baa1	A	A	Aa	Ba	Baa	A	Baa	Ba	Ba	Baa	Baa	Baa	Aa	Aa
Old Dominion Electric	A3	Stable	A2	Aa	A	Ba	A	Baa	A	Baa	A	Aa	A	A	A	Baa	A
PowerSouth	Baa1 (c)	Stable	A3	Aa	Aa	Baa	A	B	A	Baa	A	A	Baa	A	Baa	Baa	A
South Mississippi	A3	Stable	A3	Aa	Aa	B	Ba	Ba	A	A	A	Baa	A	A	Baa	Baa	Baa
Tri-State G&T Assoc.	Baa1	Stable	A3	Aa	A	Baa	Ba	B	Ba	Baa	Aaa	Baa	A	Aa	Baa	A	Aa

APPENDIX C: Observations and Outliers for Grid Mapping

Factor 1: Ratings Mapping

The following table details the mapping for the Nature of Long-Term Wholesale Power Supply Contracts/Regulatory Status factor:

FACTOR 1 (20%) — Negative Outlier / Positive Outlier

Nature of Long-Term Wholesale Power Supply Contracts and Regulatory Status

G&T Co-op	Current Rating [1]	Outlook	% of Member Load Served	Indicated Rating
Arkansas Electric	A2 (a)	Stable	91%	Baa
Associated Electric	A1	Stable	100%	Aa
Basin Electric Power	A1	Stable	100%	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	100%	Aa
Buckeye Power	A1	Negative	100%	Aa
Chugach Electric Assoc.	A3 (b)	Stable	94%	Baa
Dairyland Power	A3 (c)	Negative	100%	Aa
Georgia Transmission	A3	Stable	100%	Aa
Golden Spread Electric	A3 (c)	Stable	90%	A
Great River Energy	A3	Stable	98%	A
Hoosier Electric Power	Baa1	RUR ↓	100%	Aa
Minnkota Power	Baa1 (c)	Stable	100%	Aa
Oglethorpe Power Corp.	A3	Negative	65%	A
Old Dominion Electric	A3	Stable	100%	Aa
PowerSouth	*Baa1 (c)*	*Stable*	*100%*	Aa
South Mississippi	A3	Stable	100%	Aa
Tri-State G&T Assoc.	Baa1	Stable	100%	Aa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 1: Observations and Outliers

The nature of the long-term wholesale power contracts taken together with regulatory status is one of the most important drivers of G&T co-op ratings, so it is not surprising that there are no negative outliers. All of the rated G&T co-ops score quite well with indicated ratings of Aa , A, or Baa. Two of the five positive outliers are directly attributable to comparison of the indicated rating for the sub-factor against an actual senior unsecured Issuer Rating and would not be outliers if compared to an implied senior secured rating one notch higher than the Issuer Rating. The high ratings that so many of the G&T co-ops receive for Factor 1 help offset weaker scores in other areas, especially in Factor 2.

Notwithstanding the solid indicated ratings for Factor 1, we draw attention to the following observations. The protection afforded by wholesale power supply contracts can be eroded by changes in the contracts over time, or more suddenly, due to a need for exceptionally large rate increases.

Under a strict interpretation of the definitions, Oglethorpe Power Corp. (OPC) would receive a Ba indicated rating for Factor 1. This strict interpretation results from the fact that OPC's owned resources are currently

providing only about 65% of its members' power requirements. The situation results from a conscious decision by OPC's members to enter into power supply arrangements with third-party suppliers for their future incremental growth as permitted under the amended wholesale power supply contracts, extending through 2050. In Oglethorpe's case, we are not unduly concerned because its members remain joint and severally liable to pay all of the cooperative's costs and we believe Oglethorpe's stable supply of relatively affordable *baseload power will become increasingly valuable to its members as their needs grow and they are continually* forced to look for additional sources of supply. We believe an indicated rating of A more appropriately captures the degree of credit impact from the current relationships between OPC and its members when considered together with its rate autonomy.

Chugach Electric Association (CEA) is somewhat unique because it operates as a combined G&T co-op and distribution cooperative. As such, the 94% of its sales made to customers includes not only the 39% of energy sales made under wholesale power contracts, but also the 55% of energy sales made directly to retail customers under the tariff and certificated service territory in the state of Alaska. Moody's views direct retail revenues to commercial and residential customers to be of equal, if not somewhat better quality, than wholesale revenues derived from sales to member co-ops.

Factor 2: Ratings Mapping

The following table details the mapping for the Rate Flexibility factor:

Factor 2 (20%)
Rate Flexibility

Negative Outlier
Positive Outlier

G&T Co-op	Current Rating [1]	Outlook	Bd. Involve Adj. Mech.	Purchased Power Total MWh Sales	Indicated Rating	New Build Exposure	Indicated Rating	Carbon Exposure	Rate Shock Exposure Indicated Rating
Arkansas Electric	A2 (a)	Stable	A	15%	Aa	107%	Ba	76%	Ba
Associated Electric	A1	Stable	Aa	12%	Aa	59%	Baa	80%	Ba
Basin Electric Power	A1	Stable	Aa	17%	Aa	152%	B	82%	Ba
Big Rivers Electric Corp.	(P) Baa1	Stable	Baa	101%	B	33%	A	89%	B
Buckeye Power	A1	Negative	Aa	8%	Aa	44%	A	90%	B
Chugach Electric Assoc.	A3 (b)	Stable	A	17%	Aa	78%	Ba	90%	B
Dairyland Power	A3 (c)	Negative	Aa	8%	Aa	42%	A	90%	B
Georgia Transmission	A3	Stable	Aa	N/A	N/A	51%	Baa	N/A	Aa
Golden Spread Electric	A3 (c)	Stable	Aa	85%	B	84%	Ba	100%	B
Great River Energy	A3	Stable	Aa	31%	Baa	76%	Ba	98%	B
Hoosier Electric Power	Baa1	RUR ↓	Baa	27%	A	64%	Baa	100%	B
Minnkota Power	Baa1 (c)	Stable	Aa	27%	A	106%	Ba	100%	B
Oglethorpe Power Corp.	A3	Negative	A	8%	Aa	115%	Ba	55%	Baa
Old Dominion Electric	A3	*Stable*	A	54%	Ba	29%	A	67%	Baa
PowerSouth	Baa1 (c)	Stable	Aa	38%	Baa	29%	A	100%	B
South Mississippi	A3	Stable	Aa	63%	B	76%	Ba	81%	Ba
Tri-State G&T Assoc.	Baa1	Stable	A	32%	Baa	83%	Ba	91%	B

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 2: Observations and Outliers

Factor 2 contains the most outliers of any of the five key Factors, the substantial majority of which are negative outliers. In particular, over three-quarters of the rated universe are negative outliers for the Rate Shock Exposure sub-factor, largely reflecting the substantial dependence that the sector has on generation from carbon emitting fuels, especially coal. There are also seven negative outliers for the New Build Exposure sub-factor, reflecting the growing need for generating capacity and transmission infrastructure for those G&Ts as they have either grown into

what excess capacity they previously had or are projecting growth in demand that exceeds current capabilities. In particular, Oglethorpe's New Build Exposure relates to its plans to participate in construction of a new nuclear plant, which contributed to the recent change in its rating outlook to negative from stable.

Big Rivers, Old Dominion, Golden Spread, and South Mississippi are all negative outliers for the sub-factor measuring Purchased Power as a Percentage of Sales. We anticipate that Big Rivers' outlier status will improve prospectively following the recently completed unwind transaction which re-establishes its direct rights to power produced from its generation assets previously leased to LG&E. Golden Spread's negative outlier status may also improve as it pursues construction of additional generation capacity. Old Dominion and South Mississippi may also seek to increase their respective owned generating capacity; however, in the near term we believe purchased power will remain integral to their resource strategy.

The low ratings for so many of the G&Ts relating to sub-factors in Factor 2 are largely balanced by higher scores in Factor 1 and Factor 4. The rate autonomy and relatively low rates for so many of the G&Ts make it more likely that the members will accept what in many instances will be the continuation of significant expected rate increases over the next several years even after a series of rate increases already implemented over the past few years.

The two positive outliers for the sub-factor relating to Board Involvement/Rate Adjustment Mechanisms are directly attributable to comparison of the indicated rating for the sub-factor against an actual senior unsecured Issuer Rating and would not be outliers if compared to an implied senior secured rating one notch higher than the Issuer Rating.

Factor 3: Ratings Mapping

The following table details the mapping for the Member Profile factor:

Factor 3 (10%) Member / Owner Profile						Negative Outlier / Positive Outlier
G&T Co-op	Current Rating [1]	Outlook	Res. Sales/ Total Sales (%)	Indicated Rating	Mbrs. Equity / Capitalization (%)	Indicated Rating
Arkansas Electric	A2 (a)	Stable	50%	A	39%	Baa
Associated Electric	A1	Stable	71%	A	50%	A
Basin Electric Power	A1	Stable	36%	Ba	35%	Baa
Big Rivers Electric Corp.	(P) Baa1	Stable	18%	B	34%	Baa
Buckeye Power	A1	Negative	60%	A	50%	A
Chugach Electric Assoc.	A3 (b)	Stable	51%	A	43%	Baa
Dairyland Power	A3 (c)	Negative	70%	A	46%	Baa
Georgia Transmission	A3	Stable	70%	A	43%	Baa
Golden Spread Electric	A3 (c)	Stable	58%	A	45%	Baa
Great River Energy	A3	Stable	57%	A	45%	Baa
Hoosier Electric Power	Baa1	RUR ↓	65%	A	61%	Aa
Minnkota Power	Baa1 (c)	Stable	62%	A	45%	Baa
Oglethorpe Power Corp.	A3	Negative	68%	A	43%	Baa
Old Dominion Electric	A3	Stable	63%	A	36%	Baa
PowerSouth	Baa1 (c)	Stable	69%	A	47%	Baa
South Mississippi	A3	Stable	65%	A	53%	A
Tri-State G&T Assoc.	Baa1	Stable	33%	Ba	49%	Baa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 3: Observations and Outliers

Indicated ratings for Factor 3 map reasonably well to the actual ratings for each of the 17 rated G&T co-ops in this methodology, with just one positive outlier and two negative outliers.

Basin Electric Power Cooperative and Big Rivers are negative outliers for residential sales as a percentage of total sales to retail customers. In Basin Electric's case this is primarily because of the relatively high percentage of sales that Basin makes to non-members due to excess generation capacity. Importantly, off-system sales to non-members have served Basin well through the years and has enabled Basin to avoid member rate increases that otherwise would have been needed to meet financial covenants. Basin's demand growth from its members in recent years has enabled it to grow into some of its excess capacity. As Basin's sales to members continue to increase and off-system sales decline, the percentage of residential sales should continue to increase as it has over the past few years, albeit remaining an outlier. Big Rivers' negative outlier status is directly attributable to the high concentration of sales that its largest member/owner, Kenergy, makes to two aluminum smelters.

The lone positive outlier for Factor 3 relates to Hoosier Electric's members' consolidated equity as a percentage of equity. This status is more a function of the recent downgrade of Hoosier's rating than any noteworthy strengthening of the equity portion of total capitalization.

Factor 4: Ratings Mapping

The following table details the mapping for the Financial Metrics factor:

Negative Outlier
Positive Outlier

G&T Co-op	Current Rating [1]	Outlook	TIER	Indicated Rating	DSC	Indicated Rating	FFO / Debt	Indicated Rating	FFO / Interest	Indicated Rating	Equity/ Total Cap.	Indicated Rating
Arkansas Electric	A2 (a)	Stable	1.31x	A	1.19x	Baa	9%	A	2.6x	Aa	40%	Aa
Associated Electric	A1	Stable	1.29x	A	1.27x	A	6%	A	2.1x	A	20%	Baa
Basin Electric Power	A1	Stable	2.23x	Aaa	1.50x	Aa	10%	Aa	3.0x	Aa	30%	A
Big Rivers Electric Corp.	(P) Baa1	Stable	1.51x	Aa	1.54x	Aa	6%	Baa	1.9x	Baa	-18%	B
Buckeye Power	A1	Negative	1.36x	A	1.36x	A	7%	A	2.6x	Aa	26%	A
Chugach Electric Assoc.	A3 (b)	Stable	1.25x	A	1.84x	Aa	11%	Aa	2.6x	Aa	29%	A
Dairyland Power	A3 (c)	Negative	1.00x	Ba	1.04x	Ba	3%	Baa	1.6x	Baa	12%	Baa
Georgia Transmission	A3	Stable	1.19x	Baa	1.09x	Ba	4%	Baa	1.9x	Baa	10%	Baa
Golden Spread Electric	A3 (c)	Stable	5.02x	Aaa	3.93x	Aaa	31%	Aaa	5.7x	Aaa	51%	Aaa
Great River Energy	A3	Stable	1.34x	A	1.12x	Baa	7%	A	2.4x	A	13%	Baa
Hoosier Electric Power	Baa1	RUR ↓	1.40x	A	1.37x	A	8%	A	2.5x	Aa	13%	Baa
Minnkota Power	Baa1 (c)	Stable	1.17x	Baa	1.11x	Baa	5%	Baa	2.0x	A	36%	Aa
Oglethorpe Power Corp.	A3	Negative	1.07x	Ba	1.09x	Ba	6%	Baa	1.9x	Baa	11%	Baa
Old Dominion Electric	A3	Stable	1.28x	A	1.46x	Aa	7%	A	2.2x	A	24%	A
PowerSouth	Baa1 (c)	Stable	1.34x	A	1.20x	A	5%	Baa	2.1x	A	10%	Baa
South Mississippi	A3	Stable	1.36x	A	1.18x	Baa	7%	A	2.3x	A	14%	Baa
Tri-State G&T Assoc.	Baa1	Stable	1.72x	Aaa	1.13x	Baa	8%	A	2.8x	Aa	15%	Baa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 4: Observations and Outliers

Factor 4 takes into account historical financial statements. Historic results help us to understand the pattern of a G&T's financial and operating performance and how the G&T compares to its peers. While Moody's rating

committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes.

Although a significant number of the sub-factors in Factor 4 map reasonably well to a G&T's actual rating, there are several instances where positive outlier status is evident. Most notably, Golden Spread is a positive outlier for all its key metrics, reflecting conservative financing strategies through the years. We expect that this situation will begin to change over the next several years as Golden Spread begins to rely on debt financing to fund its investment in new generation capacity. Other positive outliers for various metrics include Basin Electric, Big Rivers, Hoosier Energy, Minnkota Power, and Tri-State G&T Association. The strength of these scores helps balance the weaker scores these G&Ts have in Factor 2, especially as it relates to Rate Shock Exposure and New Build Exposure.

Georgia Transmission Corporation, Oglethorpe Power Corporation, and Dairyland Power are negative outliers on TIER and/or DSC, reflecting greater acceptance by their respective management and boards to manage results close to the minimum required levels contained in their debt indentures. Big Rivers is a negative outlier for equity as a percentage of Total Capitalization, reflecting its negative net worth that has prevailed for many years following approval of its plan of reorganization when it emerged from bankruptcy proceedings. The negative outlier status will eventually become a moot point as the G&T's net worth turns substantially positive following completion of the company's unwind transaction.

Factor 5: Ratings Mapping

The following table details the mapping for the Size factor:

Factor 5 (10%) G&T Size					Negative Outlier Positive Outlier	
G&T Co-op	Current Rating [1]	Outlook	Megawatt Hour Sales (Millions)	Indicated Rating	Net PP&E ($ Billions)	Indicated Rating
Arkansas Electric	A2 (a)	Stable	13.2	A	$0.80	Baa
Associated Electric	A1	Stable	23.4	Aa	$1.69	A
Basin Electric Power	A1	Stable	19.5	A	$2.41	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	5.2	Baa	$0.91	Baa
Buckeye Power	A1	Negative	9.1	Baa	$1.22	A
Chugach Electric Assoc.	A3 (b)	Stable	2.8	B	$0.46	Baa
Dairyland Power	A3 (c)	Negative	6.7	Baa	$0.97	Baa
Georgia Transmission	A3	Stable	N/A	N/A	$1.49	A
Golden Spread Electric	A3 (c)	Stable	7.6	Baa	$0.20	B
Great River Energy	A3	Stable	15.0	A	$2.08	Aa
Hoosier Electric Power	Baa1	RUR ↓	10.9	Baa	$0.80	Baa
Minnkota Power	Baa1 (c)	Stable	4.9	Ba	$0.24	B
Oglethorpe Power Corp.	A3	Negative	23.3	Aa	$3.64	Aa
Old Dominion Electric	A3	Stable	10.0	Baa	$1.02	A
PowerSouth	Baa1 (c)	Stable	9.0	Baa	$1.23	A
South Mississippi	A3	Stable	9.9	Baa	$0.79	Baa
Tri-State G&T Assoc.	Baa1	Stable	19.0	A	$2.57	Aa

[1] Ratings are senior secured unless otherwise noted.

(a) Secured Facility Bonds ranking junior to RUS security

(b) Senior Unsecured Rating; No secured debt in capital structure

(c) Issuer Rating

Factor 5: Observations and Outliers

Even the largest G&T co-op, Oglethorpe Power Corporation, is considered to be relatively small by investor-owned electric utility standards, so it is not surprising that there is only one positive outlier in Key Factor 5. The three negative outliers are Chugach Electric, Golden Spread, and Minnkota, reflecting smaller than average size for the rated universe.

There are offsetting considerations in these three cases that merit comment. Although Chugach Electric is a negative outlier for megawatt hours sold it is by far the largest power provider in the state of Alaska and is geographically isolated, which tends to temper concern about its small size. In the case of Golden Spread and Minnkota, there are large capital programs under way, which over time may mitigate their respective negative outlier status for net property, plant and equipment.

APPENDIX D: G&T Co-op Industry Overview

G&T co-ops represent one of the three main forms of ownership for enterprises involved in the generation and delivery of electricity. Investor owned utilities (IOUs) constitute a sizeable majority of the U.S. electricity sector, with government owned municipal or public power entities representing the second largest segment of the market, and G&T co-ops being by far the smallest segment. G&T co-ops do not directly compete with each other or with investor owned utilities or government owned entities in a substantial way because cooperatives mainly provide service to their owner members under long term all requirements power contracts.

The A2 average (senior most) rating assigned for G&T co-ops equals the average rating for municipal or public power entities, and is two notches higher than the Baa1 average rating for (IOUs). G&T co-ops tend to be significantly smaller than investor owned utilities but have higher ratings because they are able to raise rates without the regulatory review required for investor owned utilities. G&T co-ops also face less competition given their contractual relationship with their member owners.

The following chart compares some of the characteristics that distinguish the risk profiles of these three subsets of the U.S. power sector.

[illegible]	[illegible]	[illegible]
Rate regulated	Most are not rate regulated but their owners may be	Not rate regulated
Profit seeking; operated for the benefit of public shareholders with obligations to serve regulated ratepayers	Not-for-profit; operated for the benefit of their owner members	Operated for public benefit for the region served
Most are larger; may have multiple entities in an issuer family	All are small relative to IOUs	Most are small relative to IOUs
Subject to competition in the wholesale market; sometimes in the retail market	Little competition	Little competition
Some history of defaults, usually as a result of needing rate increases that are too large to be acceptable to ratepayers	Some history of defaults; usually due to need for rate increases that are too large to be acceptable to members	Defaults have been extremely rare
Can file Chapter 11 bankruptcy	Can file Chapter 11 bankruptcy	More impediments to bankruptcy but may be able to file Chapter 9
Tend to have higher rates compared to municipal or public power	Rates tend to be comparable to IOUs	Tend to have lower rates than G&T co-ops and IOUs
Rely extensively on capital markets	Most borrow from the Rural Utilities Service and cooperative financial institutions; larger issuers access the capital markets	Rely on public and private markets for financing needs; may have access to government funding if needed

Comparison with Joint Power Agencies

Moody's rates approximately $35 billion of bonds issued by Joint Power Agencies (JPAs), which have some characteristics in common with electric generation and transmission cooperatives. Both are nonprofit enterprises and are governed by their members. Cooperatives as well as many JPAs serve small rural communities in the U.S. A significant difference between the two is the greater ability of JPAs to issue low cost tax-exempt debt, although cooperatives may borrow at below market rates through the federal Rural Utilities Service.

Since the 1970's, groups of city-owned electric utilities have established JPAs to pool resources to finance the construction of new generation facilities or to jointly purchase electric power supply. Participating members of

JPAs are contractually obligated for power supply through take-or-pay and take-and-pay power sales agreements. These agreements are the underlying security for tax-exempt debt issued by JPAs. The power sales agreements are structured to have the same term as the debt issue.

JPAs have unregulated rate-setting authority and their municipal utility participants can recover costs by independently raising retail rates. The current median municipal scale rating of JPAs is A2. After a period of low debt issuance, JPAs have accelerated the pace of borrowing to finance ownership in new generation plants in order to assist their participant members in meeting demand growth and also to diversify their generation fuel mix.

The key rating factors Moody's considers for JPA ratings include municipal utility participant credit quality, pricing power and market position, as well as governance structure and management abilities of these public sector organizations. Financial position, capital spending, and structural features of borrowing instruments are also important. Key questions embedded in our analysis of these factors are:

- How economic are power sales contracts relative to competitors?

  How are the power supply contracts structured, and what are the bond security provisions?

  What is the average weighted credit quality of participants? What are the demographic and economic characteristics of the service areas of the participating municipal electricity distributors?
- How do JPAs manage their balance sheet and plan for capital spending in order to position the JPA to meet future demand growth and competition?

The price of power the JPA supplies, and the reliability of the power supply, are among the most significant drivers of JPA credit ratings given the importance of these factors to their municipal utility participants. JPAs with the highest cost power are generally rated lower than those with more competitive price structures.

APPENDIX - E

Key Rating Issues over the Intermediate Term

Global Climate Change and Environmental Awareness

There have been significant increases in environmental expenditure estimates among G&T co-ops with significant coal fired generation in recent years as policymakers have mandated pollution control measures and emissions limitations in response to public concerns over carbon. These expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. G&T co-ops may have to implement substantial additional reductions in power plant emissions and could experience progressively higher capital expenditures over the next decade. In the U.S., the planned construction of several new coal plants have been cancelled or at least delayed as a result of opposition from regulators, political leaders, and the public or because cheaper alternatives appeared more compelling due to the significant increase in coal plant construction costs.

Large Capital Expenditures and Rising Costs for New Generation and Transmission

In order to meet rising electricity demand as the U.S. slowly emerges from a recession, many G&T co-ops intend to purchase generating plants or plan to build additional peaking and base load generating capacity, while correspondingly taking steps to upgrade and/or add to transmission infrastructure. As of end of 2008, the aggregate net property plant and equipment for rated G&T co-ops was approximately $12 billion with about an additional $8 billion of capital expenditures planned over the next five years. For those G&Ts that elect to participate in the construction of large, highly capital intensive nuclear plants, which have not been built in the U.S. in many years, the challenges could be particularly daunting and significantly pressure their credit quality.

Larger Rate Increases May Test Members' Willingness To Raise Rates

After a period of rate stability or rate decline throughout the 1980's and 1990's, G&T co-ops are increasing the wholesale rates that they charge their members. The impact of higher prices for fuel and purchased power has not been fully experienced by member co-ops because some purchase contracts have not yet been reset to new market levels.

G&Ts will likely impose large rate increases on co-op members when the G&T's power purchase contracts expire if that coincides with a period of rising market prices or when a large new generating plant is being constructed. Very large increases could test the willingness of members to pay higher rates.

G&Ts who choose to defer increasing rates to their members in the face of sharply higher costs or who are unable to gain approval from regulators to do so when rate regulation applies will likely experience a deterioration in their key credit metrics. Inability to obtain regulatory approval for rate increases has contributed to the bankruptcy of G&T co-ops in the past. As an alternative to imposing a large rate increase at one time, most G&T co-ops try to pursue a strategy of smaller, more frequent rate increases to be phased in over a period of years.

Rates charged by G&T co-ops need to be regionally competitive with rates charged by other power providers. Rate competitiveness of G&T co-ops relative to other power providers is important because it affects the willingness of co-op members to accept rate increases when costs increase. With most other power providers currently facing similar commodity cost volatility and capital spending requirements, as well as more expensive insurance and pension benefits, we do not expect that the rates that G&T co-ops charge their members will be less competitive than those charged by other power providers.

Reliance on Low-Cost Loans from U.S. Government Sponsored Agencies

G&T co-ops rely heavily on low cost loans from the Rural Utilities Service of the U.S. Department of Agriculture (RUS) and from RUS guaranteed loans provided by the Federal Financing Bank (FFB), a government funding arm.

In addition to the RUS, G&T co-ops also rely heavily on loans provided by cooperative financial institutions such as the National Rural Utilities Cooperative Finance Corporation (CFC; A1 senior secured; stable outlook) and CoBank, and local commercial banking institutions.

The RUS is the single largest provider of debt financing to the sector. Given the history of political support for the RUS loan program, our ratings reflect our assessment that the probability of systemic withdrawal of such low cost funding is low. The ratings do, however, incorporate the RUS decision not to provide loans for the construction of base load coal and nuclear plants.

Some cooperatives have elected to repay all RUS loans or otherwise obtain lien accommodations in order to obtain more financial flexibility, which results in a greater reliance upon the capital markets as a source of funding. However, the RUS requires that some of its borrowers obtain at least 30% of their financing from other sources. Larger G&T co-ops, such as those in Moody's rated universe, have sought to increase financial flexibility by accessing the capital markets. We anticipate that more G&T co-ops will do likewise in the future given the RUS decision not to lend for the construction of base load coal and nuclear plants.

Moody's Related Research

Industry Outlooks:

- U.S Regulated Electric Utilities, Six-Month Update, July 2009 (118776)
- U. S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- EMEA Electric and Gas Utilities, November 2008 (112344)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)

Rating Methodologies:

- Regulated Electric and Gas Utilities (118481)
- Unregulated Utilities and Power Companies, August 2009 (118508)
- Regulated Electric and Gas Networks, August 2009 (118786)
- Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations - Part I, July 2005 (93570)

Special Comments:

- Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)
- Carbon Risks Becoming More Imminent for U.S. Electric Utility Sector (115175)
- New Nuclear Generation: Ratings Pressure Increasing (117883)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

U.S. Electric Generation & Transmission Cooperatives

Report Number: 121189

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Moody's Investors Service

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

EXHIBIT
MEC-2
ADMITTED

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-01772A-09-0472

REJOINDER

TESTIMONY

OF

CARL N. STOVER, JR.

(CONSULTANT)

ON BEHALF OF

MOHAVE ELECTRIC COOPERATIVE, INC.

October 6, 2010

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I. INTRODUCTION

Q. Please state your name and business address.

A. Carl N. Stover, Jr. My business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112.

Q. Are you the same Carl N. Stover, Jr. who filed rebuttal testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of the Rejoinder Testimony that you are presenting at this time?

A. My rejoinder testimony discusses the lack of support on the record for the 1.40 debt service coverage ("DSC") and the additional $1.4 million in annual revenue Commission Staff ("Staff") is recommending over that being requested by Arizona Electric Power Cooperative ("AEPCO"). My rejoinder testimony focuses on rebuttal testimony presented by Staff witness John Antonuk and what he indicates justifies the Staff's DSC. I am also renewing the request for the Commission to approve the requests made by AEPCO on June 2, 2010 to approve a new power agreement with TRICO and amendments to existing power contracts with Mohave, Sulphur Springs Valley Electric Cooperative ("SSVEC"), Duncan Valley Electric Cooperative, Inc. ("Duncan") and with Graham County Electric Cooperative, Inc. ("Graham").

II. PARTIES SUPPORTING 1.32 DSC

Q. Which parties in the proceeding support a 1.32 DSC rather than the 1.40 DSC recommended by Staff?

A. In addition to the Applicant, AEPCO, its Member Intervenors, SSVEC, TRICO Electric Cooperative ("TRICO"), and Mohave Electric Cooperative, Inc. ("Mohave") all support a 1.32 DSC and the lower revenue requirement necessary to attain a DSC of 1.32. These Member Intervenors are customers of AEPCO and purchase approximately ninety one percent (91%) of the power supplied to the Class A Member systems by AEPCO. Although they have not intervened, it is my understanding that the remaining AEPCO members also support AEPCO's proposed revenue level and the resulting 1.32 DSC.

Q. Which parties support a 1.40 DSC and the higher revenue requirement recommended by Staff?

A. Staff is the only party supporting the higher DSC of 1.40 and the higher revenue requirement.

Q. Does the ACC Staff believe that the AEPCO requested DSC of 1.32 is unreasonable?

A. No. Staff witness Smith states that the AEPCO proposed DSC is within the range of reasonableness necessary to maintain an investment grade rating. *See* Smith Surrebuttal Testimony, page 3, line 17.

III. 1.40 DSC RESULTS IN INCREASED RECOMMENDED REVENUES AND NET MARGIN

Q. What is the difference in revenue requirement associated with a DSC of 1.32 versus a DSC of 1.40?

A. The Staff recommended DSC, results in a revenue requirement <u>increase</u> for AEPCO of $231,014 over test year revenues, while the AEPCO proposed DSC results in a revenue requirement <u>decrease</u> of $1,172,317 for AEPCO. The difference in the two positions is $1,403,331.

Q. How does the net margin needed to achieve a 1.32 DSC differ from that needed to achieve a 1.40?

A. Table 1 shows the calculation of the net margin associated with a 1.32 and 1.40 DSC. Staff's higher DSC provides AEPCO $1,403,331 more in its net margin than achieved with the 1.32 DSC requested by AEPCO. In short, every additional dollar recommended by Staff flows straight to AEPCO's net margin. Table 1 also shows the margin requested by AEPCO in the amended filing and the fact that the AEPCO rebuttal position results in an increase of approximately $1.2 million above the original request. This adjustment reflects AEPCO and the Members recognition of risk and volatility issues given the Staff's recommended cost adjustments.

		Reference	(A) AEPCO As Amended	(B) Staff Proposed	(C) AEPCO Rebuttal
1	Net Margin		$ 3,236,593	$ 5,462,907	$ 4,059,576
2	Plus: Interest	L10	$ 10,812,194	$ 10,812,194	$ 10,812,194
3	Plus: Depreciation	GEP-4, Line 23	$ 8,348,168	$ 8,317,632	$ 8,317,632
4	Cash Before Debt Svc	L1 + L2 + L3	$ 22,396,955	$ 24,592,733	$ 23,189,402
5	Debt Service	L11	$ (17,566,238)	$ (17,566,238)	$ (17,566,238)
6	Cash After Debt Svc	L4 + L5	$ 4,830,717	$ 7,026,495	$ 5,623,164
7	DSC	L 4/L11	1.275000088	1.400	1.320
8	TIER	(L1+L2)/L2	1.299	1.505	1.375
	Debt Service				
9	Principal	GEP-4 Line 28	$ 6,754,044	$ 6,754,044	$ 6,754,044
10	Interest	GEP-4 Line 27	$ 10,812,194	$ 10,812,194	$ 10,812,194
11	Total	L9 + L10	$ 17,566,238	$ 17,566,238	$ 17,566,238

Table 1

IV. THE RECORD DOES NOT SUPPORT A 1.40 DSC FOR AEPCO

Q. Who is the Staff witness that is recommending the 1.40 DSC?

A. Mr. Vickroy filed direct testimony supporting the Staff recommended DSC.

Q. Did you file rebuttal testimony related to Mr. Vickroy's recommendations?

A. Yes, I did. I explained that Mr. Vickroy's use of the Moody's rating criteria was incomplete and faulty because Mr. Vickroy focused on a few negative indicators and did not discuss all the relevant rating criteria. When all the criteria are examined, the 1.40 DSC is unnecessary for AEPCO to maintain an investment grade rating – a fact confirmed by the testimony of Mr. Smith. *See* Smith Surrebuttal Testimony, page 3, line 17.

Q. Did Mr. Vickroy or any Staff witness address your rebuttal testimony?

A. No. Mr. Vickroy did not file any surrebuttal testimony. Although Mr. Antonuk at page 3, lines 21 - 23 of his Surrebuttal Testimony indicates Mr. Vickroy is prepared to 'respond at hearing' regarding Staff's concern about AEPCO's ability to withstand significant and sudden changes that may affects margins, cash flow and financial health and responsiveness, my rebuttal testimony was not discussed by Mr. Vickroy or any other Staff witness in their surrebuttal testimony. It therefore is uncontroverted and unrebutted.

Q. Does Staff continue to recommend a 1.40 DSC?

A. Yes. Mr. Antonuk's and Mr. Smith's Surrebuttal Testimony indicate Staff continues to propose a DSC of 1.40. *See* Antonuk Surrebuttal Testimony, page 4, line 11; Smith Surrebuttal Testimony, page 3, lines 21-22.

Q. What is the basis for Staff's continuing support of a 1.40 DSC?

A. Mr. Smith indicates that Mr. Antonuk's Surrebuttal Testimony presents Staff's reasoning for continuing to support a 1.40 DSC. *See* Smith Surrebuttal Testimony, page 3, lines 21-22. In addition to the reference to Mr. Vickroy I have already discussed, Mr. Antonuk indicates "energy and fuel volatility form a primary concern of AEPCO to withstand financial reverses. The combination of AEPCO's lower DSC ratio and the recovery lag remain of concern." *See* Antonuk Surrebuttal Testimony, page 4, lines 9 - 11.

Q. Is Mr. Antonuk's reference to the volatility of fuel costs a sufficient concern for the Commission to adopt Staff's higher DSC and higher revenue requirement and net margin recommendations?

A. No. Changes in fuel costs incurred by AEPCO in providing service are recovered through the Commission approved fuel and purchased power adjustment clause ("FPPAC"). Changes in fuel costs are subject to recovery (or refund) after review and authorization by the Commission. The FPPAC insulates AEPCO from fuel cost volatility.

Q. Does Mr. Antonuk explain what he means by energy volatility?

A. No.

Q. Is AEPCO subject to energy volatility that requires the Commission to provide AEPCO a DSC, a net margin and revenues beyond the level requested by AEPCO?

A. No. There are two components to energy that might create uncertainty. The first is changes in the recovery of costs when energy sales increase or decrease. This is really a function of whether the rate design properly reflects fixed and variable cost incurrence. If fixed costs are recovered in the energy charge, then the level of energy sales will impact recovery of fixed costs. A decrease in sales can result in under-recovery of fixed costs. Staff has approved AEPCO's rate design. I have reviewed the AEPCO rate design and find AEPCO's fixed costs are recovered in the fixed charges and the costs that vary as a function of the energy delivered are recovered in the energy charges. Therefore, changes in energy volume related to sales should not unreasonably impact recovery of fixed costs.

Q. What is the second component that might create energy volatility?

A. The second component is the cost of energy associated with purchased power.

Q. Is the energy component of AEPCO's purchased power a basis for increasing margins to off-set risk through a higher DSC?

A. No. As previously discussed, changes in the cost of the energy component of purchased power from that included in AEPCO's base rates is recovered (or refunded to Members) as part of AEPCO's FPPAC. As such the FPPAC insulates AEPCO from volatility associated with changes in both fuel and purchased power energy costs.

Q. Does AEPCO's FPPAC insulate AEPCO from volatility in other cost components?

A. Yes. The FPPAC includes a number of different components. Gobel Rebuttal Exhibit GLG-3 shows the cost components included in the FPPAC. They include:

1. Fuel Cost (gas and coal)
2. Purchased Power Cost Energy (Acct 555)
3. Purchased Power Cost Demand (Acct 555)
4. Transmission Firm and Non-Firm (Acct 565)

5. Changes in Firm Contract revenues both demand and energy related, changes in resource economy energy revenue, and changes in scheduling revenues.

The FPPAC, thus, minimizes potential erosion of earnings associated with changes, from those included in base rates, of all the foregoing cost components associated with providing service to AEPCO's Members that are included in the FPPAC. These costs are then recovered (or refunded) over kWhs sold as authorized by further Commission orders.

Q. Why does the FPPAC also include changes in firm contract, economy, and scheduling revenues?

A. These components are included because they were treated as credits in the development of AEPCO's base rates.

Q. Has Mr. Antonuk raised any other concern regarding energy costs?

A. Mr. Antonuk also references recovery lag as a concern. *See* Antonuk Surrebuttal Testimony, page 4, line 11.

Q. What lag concern is associated with fuel and energy costs?

A. While in the long term, fuel and energy cost volatility are addressed by AEPCO's FPPAC, there can be a cash flow problem in the near term because of the lag in the reconciliation mechanism of the FPPAC.

Q. Has this concern been addressed?

A. Yes. My understanding is that Mr. Antonuk made specific recommendations related to the FPPAC. Mr. Pierson responded to the two recommendations in his rebuttal testimony. The first dealt with options to shorten the recovery period. Mr. Pierson pointed out that a change has recently been made and rather than studying a new option now that AEPCO believes the efficacy review option granted by the Commission in the last rate order should be continued. *See* Pierson Rebuttal Testimony, page 16, line 21. The second dealt with a provision for a temporary surcharge to which Mr. Pierson agreed. *See* Pierson Rebuttal Testimony, page 17, line 7.

Q. Did Mr. Antonuk find Mr. Pierson's position acceptable?

A. Yes. Mr. Antonuk stated he finds the FPPAC recommendations in Mr. Pierson rebuttal testimony to be acceptable. *See* Antonuk Surrebuttal Testimony, page 4, line 12.

Q. Has Staff provided any other basis for its continued support for a 1.40 DSC and a recommended rate increase $1.4 million greater than the amount AEPCO has requested and its Members support?

A. No. I believe Mr. Antonuk's concerns have been addressed.

Q. Do you have any other comments concerning the volatility issue?

A. Yes. AEPCO, as well as the Members, have to deal with cost volatility on a continuing basis. It is certainly not a new issue. As I indicated in my rebuttal testimony AEPCO has been able to substantially improve its financial conditions since the last rate case. They were able to accomplish this during one of the most turbulent periods for electric utilities. Gas prices over the last few years have been very volatile and we have experienced historic highs and lows. I think this says a great deal about how AEPCO has been able to mitigate adverse impacts associated with volatility.

Another point is that AEPCO has created value in its coal inventory. I know that AEPCO is looking for ways to capture that value so as to improve its cash position. This is another example as to how AEPCO has been able to deal with volatility in costs.

Q. Do you have an estimate of the impact of AEPCO's proposed rates?

A. Yes. Table 2 is a summary comparing the total cost for each Class A Member under existing and AEPCO proposed rates.

Class of Service	(A) Energy (1) kWh	(B) Billing MW	(C) Present Revenue $	(D) Proposed Revenue $	(E) Change $	(F) Change %
Anza	51,283,408	96,412	3,353,127	3,260,032	(93,095)	-2.78%
Duncan	28,079,760	57,180	1,901,744	1,858,064	(43,680)	-2.30%
Graham	156,396,015	324,562	10,683,325	10,446,493	(236,832)	-2.22%
Mohave	875,380,060	1,723,399	54,205,506	55,489,632	1,284,126	2.37%
Sulphur	847,038,000	1,629,806	52,026,365	52,370,038	343,673	0.66%
Trico	646,286,536	1,361,311	44,448,572	42,022,063	(2,426,509)	-5.46%
Total Class A	2,604,463,779	5,192,670	166,618,639	165,446,322	(1,172,317)	-0.70%

Average Wholesale Rate	% Energy	$/MWh	$/MWh	$/MWh
Anza	1.97%	65.38	63.57	(1.82)
Duncan	1.08%	67.73	66.17	(1.56)
Graham	6.00%	68.31	66.80	(1.51)
Mohave	33.61%	61.92	63.39	1.47
Sulphur	32.52%	61.42	61.83	0.41
Trico	24.81%	68.78	65.02	(3.75)
Total	100.00%	63.97	63.52	(0.45)

Note:
1. Energy Values include total requirement based on AEPCO adjustments

Table 2

Q. Do you have an estimate of how AEPCO's proposed rates will impact the average customer of an AEPCO Member?

A. Table 2 shows the average rate per kWh sold. The values are shown at the wholesale level. Depending on the level of distribution losses the impact of the rate adjustment at the retail level will vary. For estimating purposes, given the increase for Mohave of $0.00147/kWh a residential customer using 1,000 kWh during the month will experience, on average, an increase of $1.60/month.

V. THE AMENDED AND NEW POWER CONTRACTS BETWEEN AEPCO AND ITS MEMBERS SHOULD BE APPROVED

Q. What power contracts are AEPCO and its Members specifically requesting the Commission address?

A. On June 2, 2010, AEPCO filed two separate requests for Commission approval of its power agreements with its members. The first Request seeks Commission approval of (1) a new Partial-Requirements Capacity and Energy Agreement between AEPCO and TRICO and (2) amendments to the existing Partial-Requirements Agreements between AEPCO and SSVEC and AEPCO and MEC. The second Request seeks Commission approval of amendments to AEPCO's existing Wholesale Power Contracts with Duncan and with Graham, both of which are all requirements members of AEPCO.

Q. HAS STAFF OPPOSED THE COMMISSION'S APPROVAL OF THE AMENDED AND NEW POWER CONTRACTS BETWEEN AEPCO AND ITS MEMBERS?

A. No. In fact by approving AEPCO's cost of service study and general rate design, Staff is indicating that the amended and new power contracts between AEPCO and its Members are fair and reasonable and should be approved.

Q. Has the Commission approved AEPCO's power contracts with its members in the past?

A. Yes. Decision No. 63868, dated July 25, 2001 approved and confirmed various transactions enabling AEPCO to restructure into three affiliated entities. Included was the approval of the partial requirements relationship between AEPCO and Mohave. Then by Decision No. 70105, dated December 21, 2007, the Commission approved the conversion of SSVEC to a partial-requirements member and to implement a second amendment to the Mohave Partial-Requirements Capacity and Energy Agreement. As the requests for Commission approval of the new agreement with TRICO and the amendments to existing contracts with Mohave, SSVEC, Duncan and Graham are unopposed, and the rates and charges recommended by all parties to this proceeding reflect the agreement and amendments, the Commission should specifically approve the requests.

1 **Q. Does this conclude your rejoinder testimony?**

2 A. Yes

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

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-01773A-09-0472

DIRECT

TESTIMONY

OF

RALPH C. SMITH

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 02, 2010

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Qualifications RCS-1

Staff Accounting Schedules RCS-2

Copies of selected AEPCO responses to discovery and other documents that are referenced in the testimony RCS-3

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-09-0472

My testimony and Attachment RCS-2 present Staff's recommended rate base, net income (margin) and revenue increase for Arizona Electric Power Cooperative, Inc. ("AEPCO"). In computing Staff's recommended revenue increase, I used the debt service coverage ("DSC") method and applied the DSC ratio of 1.40 recommended by Staff witness Vickroy.

Staff's recommended rate base is $211.8 million versus the $231.8 million requested by AEPCO. The following table summarizes Staff's recommended rate base adjustments:

Summary of Staff Adjustments to Rate Base		
Adj. No.	Description	Increase (Decrease)
B-1	Plant Held for Future Use	$ (2,551,631)
B-2	Acquisition Adjustment	$ -
B-3	Accumulated Depreciation - Retirement Work in Progress	$ (3,547,307)
B-4	Fuel Stock	$ -
B-5	Deferred Debits	$ (12,850,764)
B-6	Asset Retirement Obligation	$ (1,092,679)
	Total of Staff Adjustments	**$ (20,042,381)**
	AEPCO Proposed Rate Base (Original Cost)	$ 231,844,975
	Staff Proposed Rate Base (Original Cost)	**$ 211,802,594**

Both AEPCO and Staff have used original cost information to derive the fair value rate base. Because AEPCO is a cooperative, a DSC method is being used to derive the recommended revenue requirement, and the revenue requirement does not vary with the amount of rate base.

Staff's adjustments produce an adjusted net income (margin) of $5.232 million versus the $3.333 million proposed by AEPCO. Staff's recommended adjustments to income are summarized in the following table:

Summary of Staff Adjustments to Net Income (Margin)		**Net Income (Margin)**
Adj. No.	**Description**	**Increase (Decrease)**
C-1	Work Force Reduction	$ 898,760
C-2	Incentive Compensation	$ 681,900
C-3	Donations	$ 79,926
C-4	Lobbying Expense in Association Dues	$ 112,240
C-5	Asset Retirement Obligation - Depreciation and Accretion Expense	$ 125,720
Total of Staff's Adjustments to Net Operating Income		**$ 1,898,546**
	Adjusted Net Income per AEPCO	$ 3,333,347
	Adjusted Net Income per Staff	**$ 5,231,893**

On Attachment RCS-2, Schedule A, page 1, I present Staff's calculation of the revenue deficiency for AEPCO. As shown on Schedule A, page 1, column D, lines 16-26, using the DSC ratio of 1.40 recommended by Staff witness Vickroy, my calculations show a revenue deficiency of approximately $231,000. As shown on Attachment RCS-2, Schedule C, line 20, this represents an increase of approximately 0.13 percent over adjusted total operating revenues at AEPCO's current rates.

I. INTRODUCTION

A. Background and Qualifications

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

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society

of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 30 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington D.C.,

West Virginia, Wisconsin, and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have previously testified before the Commission on a number of occasions. I most recently testified before the Commission in Docket Nos. W-01303A-09-0343 and SW-01303A-09-0343 involving general rate case requests by Arizona-American Water Company. I testified in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS"), APS' Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, concerning proceedings involving APS base rates and other matters, and the most recent APS case, Docket No. E-01345A-08-0172, concerning an emergency rate increase and general rate case request. I also testified before the Commission in the last UNS Gas, Inc. rate cases, Docket Nos. G-04204A-08-0571, G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831, in a previous UNS Electric, Inc. rate case, Docket No. E-04204A-06-0783, as well as the last Southwest Gas Corporation rate case, Docket No. G-01551A-07-0504, and Tucson Electric Power Company rate case, Docket No. E-01933A-07-0402, among others. I also submitted direct testimony in Docket No. E-04100A-09-0496, a rate case application by Southwest Transmission Cooperative, Inc.

B. Purpose of Testimony

Q. On whose behalf are you appearing?

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

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the application for a general rate increase filed by Arizona Electric Power Cooperative, Inc. ("AEPCO" or "Company"). Specifically, I will be addressing the revenue requirement, rate base, and net operating income.

Q. Please briefly describe the information you reviewed in preparation for your testimony.

A. The information I reviewed included AEPCO's application and testimony, AEPCO's responses to data requests of Staff, information provided to me by Staff, and other publicly available information.

C. Content of Attachments to Testimony

Q. Have you attached any exhibits to be filed with your testimony?

A. Yes. I am attaching two exhibits, Attachments RCS-2 and RCS-3.

Q. What is shown in each of those attachments?

A. Attachment RCS-2 presents the results of my analysis including Staff's recommended revenue requirement, rate base and adjusted net operating income. Attachment RCS-3 presents copies of responses to data requests and selected documents that are referenced in my testimony.

D. General Background to AEPCO's Rate Request

Q. Please briefly provide some background for the request that AEPCO has made in the current proceeding.

A. AEPCO is a non-profit, certificated electric generation cooperative which serves the power needs of its four all-requirements ("ARM") and two partial requirements ("PRM") 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 primarily in the rural areas of Arizona.

AEPCO's current base rates became effective September 1, 2005 pursuant to Decision No. 68071, dated August 17, 2005. That case, Docket No. E-01773A-04-0528, used a test year ending December 31, 2003. In Decision No. 68071, the Commission had ordered AEPCO to file a rate case six months after one of its Class A Members, Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC"), completed a full calendar year as a partial-requirements member. In Decision No. 71112, the Commission granted an extension and authorized AEPCO to delay its rate case filing to October 1, 2009 using a test year ending March 31, 2009.

AEPCO filed an application on October 1, 2009 using a test year ending March 31, 2009. In that application, AEPCO requested, among other things, a revenue increase of approximately $4.023 million or a 2.41 percent increase in revenue requirements. The net increase proposed by AEPCO was a blend of a 2.83 percent <u>decrease</u> in the revenues from rates from its ARMs and a 5.39 percent <u>increase</u> in the revenues from its PRMs.[1] AEPCO's filing was intended to produce a Debt Service Coverage ("DSC") Ratio of 1.35 and operating margins of approximately $3.4 million.[2]

[1] See, e.g., Direct Testimony of AEPCO witness Gary Pierson, filed October 1, 2009, at page 2, lines 16-19.
[2] See, AEPCO, October 1, 2009 Application, at page 2, lines 3-4.

After discussions with its members and with Staff, AEPCO and its members reported that they had reached agreement on many of the issues in the rate case and would be filing revisions to the application. AEPCO filed Amended and Restated R14-2-103.B Schedules in support of its application for general rate relief with the Commission on April 20, 2010. In that revised application, AEPCO requests a net decrease in revenues of approximately $97,000 using a test year ending March 31, 2009, and a DSC of approximately 1.28.

II. REVENUE REQUIREMENT

A. Summary of AEPCO's Requested Decrease

Q. Please briefly summarize AEPCO's basis for its request for a rate decrease.

A. Using a test year ending March 31, 2009, with pro forma adjustments, AEPCO is seeking a base rate decrease of $97,000, or approximately 0.06% below AEPCO's adjusted test year electric revenue.[3] AEPCO's requested revenue is designed to produce a net margin of approximately $3.237 million, a Times Interest Earned Ratio ("TIER") of 1.30 and a DSC of approximately 1.28.[4] Consistent with its October 1, 2009 application, AEPCO has continued to request that the rates in its general rate application become effective on January 1, 2011.

Q. What is causing AEPCO's request for a revenue decrease of approximately $97,000, considering that actual test year net income only was almost $15.8 million?

A. Events occurring after the test year included higher delivered prices for coal costs as the result of new coal contracts that became effective January 1, 2009 and post-test year revenue losses through January 1, 2011. AEPCO's actual recorded results for the test year ended March 31, 2009, as summarized on Attachment RCS-2, Schedule A, column A, line 7, indicate a positive net income of approximately $15.8 million. This would indicate a

[3] AEPCO's April 30, 2010 Amended and Restated Application, Schedule A-1.
[4] Id., at Schedule A-2, "Proposed Rates" column.

significant base rate revenue decrease would be in order, but for the Company's pro forma adjustments. As explained in AEPCO witness Minson's October 1, 2009 direct testimony at pages 7-8:

> *". . . generally there are four primary cost changes which are driving the need for this request.*
>
> *First, our long-term coal arrangements expired at the end of last year and we are seeing much higher delivered coal costs as a result of the new coal contracts which became effective January 1, 2009. AEPCO's 2008 delivered cost of coal was approximately $1.90/MMBtu in 2008, but that has risen to about $3.00/MMBtu this year. Second, this rate application reflects substantial impacts to both AEPCO's cost and revenues as a result of (a) the expiration of the City of Mesa ("Mesa") 15 MW sales agreement on December 31, 2008; (b) the expiration of the Public Service Company of New Mexico ("PNM") 13 MW purchased power agreement on December 31, 2008; but, most significantly, (c) the expiration of the 100 MW Salt River Project ("SRP") 20-year sales contract on December 31, 2010. Third, most of our generating assets at Apache are now 30 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 are increasing. Finally, in order to meet the mercury control requirements of the Consent Order with the Arizona Department of Environmental Quality, AEPCO will incur significant increased costs starting in January 2011 to inject certain chemicals into the Apache Station coal-fired units combustion process.[5] AEPCO has made a pro forma adjustment to reflect the costs of those chemicals. As Mr. Pierson explains in his testimony, the overall impact of these and other adjustments on net margins is a <u>decrease</u> of more than $15 million."*

The estimated impact of AEPCO's proposed pro forma adjustments on its margins and revenue requirement is shown in the following table:

[5] It should be noted that AEPCO pro forma adjustment #11, Mercury Control Adjustment, that had been in the Company's October 1, 2001 filing, was removed from its base rate revenue requirement increase request when AEPCO filed its amended and restated application on April 20, 2010.

Description	AEPCO Adj. No.	Impact on Income (A)	Impact on Revenue Requirement (B)
I. AEPCO's Proposed Pro Forma Adjustments			
Coal Cost Adjustment	1	$ (14,946,695)	$ 14,946,695
Payroll & Pension Adjustments	2	$ (1,472,532)	$ 1,472,532
SRP Contract Expiration Adjustment	3	$ (13,210,326)	$ 13,210,326
City Of Mesa Contract Expir. Adjustment	4	$ (2,271,204)	$ 2,271,204
PRP PPA Contract Expir. Adjustment	5	$ 4,712,636	$ (4,712,636)
MEC Add. Sales Adjustment	6	$ 5,303,853	$ (5,303,853)
SSVEC Add. Sales Adjustment	7	$ 3,973,995	$ (3,973,995)
Arm Coal & Purchased Power Adjustment	8	$ 6,464,788	$ (6,464,788)
Maintenance Outage Adjustment	9	$ (2,129,298)	$ 2,129,298
SAP Software Amortization Adjustment	10	$ (824,755)	$ 824,755
Mercury Control Adjustment	11	$ -	$ -
Southpoint PPA Capacity Adjustment	12	$ 232,500	$ (232,500)
Rate Case Amortization Adjustment	13	$ (160,000)	$ 160,000
Interest Adjustment	14	$ (231,437)	$ 231,437
Revenue Synchronization Adjustment	15	$ 2,057,807	$ (2,057,807)
Totals		$ (12,500,668)	$ 12,500,668

The revenue loss and cost impacts resulting from the Salt River Project contract commence on January 1, 2011. AEPCO has indicated that is why it is requesting the new rates not take effect until that date.

As shown on Schedule A, page 2, lines 16-18, AEPCO's requested revenue decrease of $96,754 can be shown to consist of the difference between: (1) its pro forma adjusted test year net margin of approximately $3.333 million and (2) AEPCO's requested coverage requirement of approximately $3.237 million.

Q. Has AEPCO presented reconstructed cost new less depreciation ("RCND") information in its filing for determining the amount of fair value rate base?

A. No. The October 1, 2009 direct testimony of AEPCO witness Gary Pierson states at page 6, lines 19-21 that Schedules B-3 and B-4, concerning RCND rate base, were not

completed and "[a]s a non-profit cooperative, AEPCO stipulates to the use of its original cost rate base as its fair value rate base."

Q. Has Staff also used AEPCO's original cost information for determining the amount of fair value rate base?

A. Yes.

B. Summary of Staff's Recommendation

Q. What revenue increase does Staff recommend?

A. Staff recommends a base rate revenue increase of approximately $231,000.

Q. What calculations have you presented in support of that recommendation?

A. On Attachment RCS-2, Schedule A, page 1, I present a calculation of the revenue deficiency for AEPCO. As shown on Schedule A, page 1, column C, my calculations show a revenue deficiency of approximately $231,000. As shown on Attachment RCS-2, Schedule C, line 20, this represents an increase over current operating revenues of approximately 0.13 percent.

C. Test Year

Q. What test year is being used in this case?

A. AEPCO's filing is based on the historic test year ended March 31, 2009. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues

and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Rate base items that tend to fluctuate from month to month, such as materials and supplies and fuel stock, are based on a test year average level.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will typically increase as new plant is added to serve new customers, revenue will change as existing contracts expire or new ones are added, expenses will fluctuate etc. It is important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted. For example, it would be inappropriate and unbalanced to recognize only increases to labor expense occurring beyond the test year, and to ignore offsetting known and measureable decreases to labor cost.

D. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-6 and net operating income adjustment Schedules C-1 through C-5. The revenue requirement for AEPCO was based upon the ACC jurisdictional adjusted results.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony, as well as the recommended DSC coverage recommended on behalf of Staff by Randall Vickroy of Liberty Consulting. This schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to achieve Staff's recommended coverage.

Q. What is shown in each column of Schedule A, page 1?

A. Column A shows AEPCO's actual unadjusted test year results. Those actual results show that for the 12 months ending March 31, 2009, AEPCO had net margins of approximately $15.8 million. To achieve a TIER of 1.305894, based on the test year unadjusted results for AEPCO, a base rate revenue reduction of approximately $12.5 million would be in order.

Column B presents AEPCO's proposed test year adjusted results. This reflects the impact of the pro forma adjustments proposed by AEPCO. As shown on line 7, AEPCO's adjusted results show a positive net margin of approximately $3.3 million. This equates to a TIER of 1.308295 and a DSC of approximately 1.28.

As shown in column C, the Cooperative's pro forma adjusted results were used by AEPCO to derive its proposed revenue decrease of approximately $97,000 to produce its requested TIER of 1.305894 and a DSC of approximately 1.28.

Column D shows the test year adjusted results per Staff.

Column E shows the derivation of the amount of rate increase using Staff's adjusted test year operating results and Staff's recommended coverage.

Q. What is shown in each section of Attachment RCS-2, Schedule A, page 1?

A. Section I of Schedule A shows the derivation of AEPCO's net operating income. Section II shows the derivation of the revenue increase using a TIER basis. Section III shows the derivation of the revenue increase using a DSC basis. Both the TIER and DSC method of deriving a utility's revenue requirement are considered cash methods (as opposed to the rate base/rate of return method that is typically used for investor-owned utilities). Section IV shows the components of the return and the return on rate base produced by the recommended revenue increase.

A DSC ratio of 1.40[6] will result in a required operating income of $16,275,101. This equates to a 7.68 percent rate of return on Staff's adjusted Fair Value Rate Base of $211,802,594, as shown on Attachment RCS-2, Schedule A, column E, lines 32-34.

Q. How does the recommended DSC affect the amount of net income?

A. As shown on Schedule A, page 1, because Staff witness Vickroy has recommended a higher DSC than was requested by AEPCO, this produces a higher amount of required net income under Staff's recommendation.

Q. What is shown on Schedule B?

A. Schedule B presents AEPCO's proposed adjusted test year Original Cost and Staff's proposed adjusted test year Original Cost rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically

[6] This DSC equates to a TIER of 1.505254.

AEPCO Schedule B-1. Staff's recommended adjustments to rate base are summarized on Schedule B.1.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is AEPCO's adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to AEPCO's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of these adjustments is discussed in my testimony.

Q. What is shown on Schedule D?

A. Schedule D summarizes the capital structure and cost of capital that was proposed by AEPCO and the capital structure and cost of capital that is recommended by Staff witness Vickroy.

Q. Which schedules in Attachment RCS-2 show the rate base and operating income adjustments?

A. Schedules B-1 through B-6 provide further support and calculations for the rate base adjustments Staff is recommending. Schedules C-1 through C-5 provide further support and calculations for the net operating income adjustments Staff is recommending.

III. RATE BASE

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Attachment RCS-2, Schedule B. The adjustments to AEPCO's proposed rate base are summarized on Schedule B.1. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost is presented below:

Summary of Staff Adjustments to Rate Base

Adj. No.	Description	Increase (Decrease)
B-1	Plant Held for Future Use	$ (2,551,631)
B-2	Acquisition Adjustment	$ -
B-3	Accumulated Depreciation - Retirement Work in Progress	$ (3,547,307)
B-4	Fuel Stock	$ -
B-5	Deferred Debits	$ (12,850,764)
B-6	Asset Retirement Obligation	$ (1,092,679)
	Total of Staff Adjustments	**$ (20,042,381)**
	AEPCO Proposed Rate Base (Original Cost)	$ 231,844,975
	Staff Proposed Rate Base (Original Cost)	**$ 211,802,594**

As noted above, both AEPCO and Staff are using the original cost rate base as the fair value rate base in this case.

Cash Working Capital

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital

allowance is reflected as a reduction to rate base. In this situation, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. What has AEPCO proposed for Cash Working Capital?

A. AEPCO has proposed a zero amount for Cash Working Capital because it did not prepare a lead-lag study.[7]

Q. For purposes of this rate case, does Staff agree with the use of a zero amount for Cash Working Capital?

A. Yes. Since AEPCO did not prepare a lead-lag study, a zero amount should be used for Cash Working Capital.

Prepayments

Q. How has AEPCO treated Prepayments for purposes of rate base?

A. AEPCO has excluded Prepayments from rate base because of the position taken by Staff in its 2004-2005 rate case.[8]

Q. Does Staff agree that Prepayments should be excluded from rate base in the current AEPCO rate case?

A. Yes. AEPCO's exclusion of Prepayments from rate base is consistent with the position taken by Staff in AEPCO's and SWTC's previous rate cases. For example, in Docket No. E-01773A-04-0528, Staff pointed out that the cooperatives failed to conduct a lead-lag study, thus omitting a major component of Working Capital, which could decrease rate

[7] See, e.g., AEPCO's filing at Schedule B-5, page 2, and the October 1, 2009 direct testimony of AEPCO witness Gary Pierson at page 7, lines 4-6.
[8] Id., lines 6-8.

base due to the long lags applied to significant expenses such as property taxes and interest. Additionally, Staff noted that in Decision No. 58405, the Commission removed prepayments. Consequently, Staff concurs with AEPCO's exclusion of Prepayments from rate base in the current AEPCO rate case.

AEPCO-Proposed Rate Base Adjustments

Q. Did AEPCO propose any pro forma adjustments to rate base in the current AEPCO rate case?

A. No.[9]

Staff Rate Base Adjustments

Q. Is Staff proposing any adjustments to rate base that were not made by AEPCO?

A. Yes. Staff's recommended adjustments to rate base are discussed below.

B-1. Plant Held for Future Use

Q. Please discuss the adjustment to remove Plant Held for Future Use ("PHFFU") from rate base.

A. AEPCO included $2,551,631 for PHFFU in rate base. As explained by AEPCO in its response to data request STF 1-71:

> *A parcel of land was purchased in 2004 for the future site of an office complex. The carrying value of this parcel is $2,538,392.31. At this time there are no plans to begin construction of the office complex*

As explained in AEPCO's response to data request STF 2-11, AEPCO also inadvertently included $13,238 in PHFFU related to an acquisition adjustment that has been fully amortized. Although AEPCO's response to data request STF 2-11 indicates that this

[9] See, e.g., AEPCO Schedule B-1, and the direct testimony of Gary Pierson at page 6, lines 18.

acquisition adjustment has now been fully amortized, and thus had no rate base impact, AEPCO's Schedule B-1, at line 7, included the full $2,551,631 amount in rate base.

Q. Please summarize Staff's recommendation.

A. The PHFFU should be removed from rate base. AEPCO has no current plans to begin construction of the office complex on the land it had purchased in 2004 so that land is not used and useful in providing utility service. The acquisition adjustment was included by AEPCO in error in the PHFFU account. This rate base error should be removed. As shown on Attachment RCS-2, Schedule B-1, the $2,551,631 amount that AEPCO included in rate base on its Schedule B-1 should be removed.

B-2. Acquisition Adjustment

Q. Please discuss the Company's Acquisition Adjustment.

A. As described in the response to data request STF 2-11, AEPCO recorded an acquisition adjustment of $13,238 in Account 114. AEPCO's response also indicates that this amount has been fully amortized. However, AEPCO carried this amount into its proposed amount for rate base on its Schedule B-2 and Schedule B-1, by inadvertently including it in the $2,551,631 amount for Plant Held for Future Use. This item has been removed from rate base, as shown on Attachment RCS-2, Schedule B-1, as part of the PHFFU adjustment, described above.

Q. Did Staff remove the acquisition adjustment from rate base in AEPCO's last rate case?

A. Yes. Staff removed this acquisition adjustment from rate base in AEPCO's last rate case, Docket No. E-01773A-04-0528. Additionally, Staff also removed it in the prior rate case

to that one, as indicated in Decision No. 65367 (dated November 5, 2002) at page 4, lines 21-24. AEPCO's acquisition adjustment is related to SWTC's acquisition adjustment.

Q. Did AEPCO accept Staff's adjustment to remove the acquisition adjustment from rate base in AEPCO's last rate case?

A. Yes.

Q. Why should the acquisition adjustment be removed from rate base in AEPCO's current rate case?

A. Original cost rate base is calculated using the original cost of plant assets. An acquisition adjustment, by definition, is not the original cost of an asset because it is the difference between the original cost of an asset and the purchase price. Non-recognition of the acquisition adjustment in rate base is the normal ratemaking treatment. As noted above, this acquisition adjustment was removed in the last AEPCO rate case.

Q. Please summarize Staff's recommendation.

A. The acquisition adjustment that AEPCO recorded in Account 114 should be removed from rate base in AEPCO's current rate case. Because this item has already been removed as part of Staff Adjustment B-1, there is no need for a separate adjustment.

B-3. Accumulated Depreciation – Retirement Work in Progress

Q. What has AEPCO proposed for Accumulated Depreciation?

A. AEPCO proposed using $204,796,249 for Accumulated Depreciation in deriving its rate base, inclusive of the following components:

Components of Accumulated Depreciation in AEPCO's Proposed Rate Base	
Component	**Amount**
Production	$ (194,303,265)
Transmission	$ (1,580,842)
Retirements	$ 3,547,307
General	$ (10,016,425)
Elec Plt In Service	$ -
Accumulated Amortization	$ (2,443,024)
Total	**$ (204,796,249)**
Source: AEPCO filing Schedule E-5	

Q. Is Retirement Work in Progress ("RWIP") normally a component of rate base?

A. No. RWIP should reflect a coordinated treatment of the plant to be retired, accumulated depreciation, salvage value and disposal cost. The retirement should be completed before rate base is adjusted.

Q. What adjustment does Staff recommend?

A. Staff recommends increasing Accumulated Depreciation by $3,547,307 to remove RWIP from rate base as shown on Attachment RCS-2, Schedule B-3. This adjustment decreases AEPCO proposed rate base by $3,547,307.

B-4. Fuel Stock

Q. How did AEPCO determine the Fuel Stock amount it included in rate base in the current rate case?

A. AEPCO used a 12-month average to determine its proposed Fuel Stock amount of $16,033,459, as shown on AEPCO Amended & Restated Filing, April 20, 2010, Schedule B-5, page 3.

Q. How did Staff determine the Fuel Stock amount in AEPCO's last rate case?

A. Staff used a number of days burn method to determine the average cost of coal inventory, which was the method proposed by AEPCO in its last rate case. The difference between Staff and AEPCO in Docket No. E-0773A-04-0528 related to the application of the number of days burn method, and within that method primarily to Staff's use of a lower quantity of tons per burn day. During April of the calendar 2003 test year used in that case, AEPCO had changed its inventory level target from 5,300 tons per burn day to 4,100 tons, so Staff used the 4,100 ton amount in its recommendation in that case.

Q. Did changes occur during the test year that affect AEPCO's coal inventory?

A. Yes. Increased coal prices resulting from new contracts which took effect on January 1, 2009 have caused increases in the price of delivered coal that are not reflected in the test year average balance. Additionally, as explained in the direct testimony of AEPCO witnesses Minson and Pierson, and in response to data request STF 1.66(a), while making replacement arrangements in 2008 for coal to be delivered after 2008 under new contracts, AEPCO realized that the post-2008 cost of delivered coal would increase significantly both in terms of supplier rates and railroad transportation charges. Accordingly, in 2008, AEPCO developed a strategy to stockpile additional coal under the then-existing contracts to be saved and used in 2009 and 2010. AEPCO's response to data request STF 1.66(a) indicates that, without this stockpile, the impact of increased delivered coal costs would be larger than reflected in AEPCO's pro forma adjustment, which would have resulted in a larger proposed rate increase. Consequently, the average quantities of coal in the inventory for the test year are above normal levels, but AEPCO's stockpiling strategy in anticipation of substantial delivered coal cost increases would likely have saved customers money. AEPCO's fuel procurement is being reviewed by Staff, but that prudence review has not yet been completed.

Q. What Fuel Stock inventory does Staff recommend for purposes of the current AEPCO rate case?

A. For purposes of determining AEPCO's rate base at this stage of the proceeding, Staff has accepted AEPCO's proposed Fuel Stock inventory of approximately $16.033 million as shown on Attachment RCS-2, Schedule B-4, without adjustment. This acceptance is contingent upon the results of Staff's prudence investigation of AEPCO's fuel and purchased power.

B-5. Deferred Debits

Q. What amount of Deferred Debits did AEPCO include in rate base?

A. AEPCO included approximately $12.851 million of Deferred Debits in rate base. This amount is comprised of the following components:

Components of AEPCO's Rate Base Deferred Debit

Account	Description		3/31/09
1830000	Other Deferred Debits (Preliminary Engineering)	$	1,062,320
1830100	Preliminary Surveys	$	76
1831000	SPPR Project #1 - Prefunding	$	145,260
1840000	Overhauls	$	2,775,437
1860000	Misc Deferred Debits	$	-
1861000	Deferred Overhauls - "435" Prior Period	$	1,018,075
1861401	Deferred Overhauls - Steam 1	$	1,430,655
1861402	Deferred Overhauls - Steam 2	$	5,171,744
1861403	Deferred Overhauls - Steam 3	$	903,154
1861404	Deferred Overhauls - Gas Turbine 1	$	61,201
1861405	Deferred Overhauls - Gas Turbine 2	$	6,969
1861406	Deferred Overhauls - Gas Turbine 3	$	105,009
1890000	UnamortLoss/Reacquired Debt	$	170,862
	Total Deferred Debits AEPCO Included in Rate Base	**$**	**12,850,762**

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

A. No, they should not. The Deferred Debits are not generally included in rate base. Staff recommended that Deferred Debits be excluded from rate base in AEPCO's last rate case, Docket No. E-0773A-04-0528, and AEPCO agreed. Additionally, in the 1993 AEPCO rate case preceding that one, Docket No. E-01773A-92-0214, the Commission removed the Deferred Debits from rate base in Decision No. 58405. Consistent with the treatment of these items in the last two AEPCO rate cases, Staff recommends removal of the Deferred Debits from rate base as shown on Attachment RCS-2, Schedule B-5. This reduces AEPCO's proposed rate base by $12.851 million.

B-6. Asset Retirement Obligation

Q. What is an Asset Retirement Obligation?

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

Q. Is there a financial accounting statement that addresses ARO accounting?

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

As explained in AEPCO's response to data request STF 1.66(f):

> *SFAS No. 143 requires the recognition of an Asset Retirement Obligation ("ARO"), measured at estimated Fair value, for legal obligations related to decommissioning and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. The initial capitalized asset retirement costs are depreciated over the life of the related asset, with the accretion of the ARO liability classified as an operating expense. See the attached documents.*

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

A. AEPCO's response to data request STF 2-15 shows that AEPCO included a $1,092,679 ARO in Plant as of March 31, 2009. The Cooperative recorded the amount to recognize the present value of its projected retirement cost associated with the retirement of an ash pond.

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

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

Q. For what asset did AEPCO recognize an ARO?

A. AEPCO recognized an ARO pertaining to a coal ash pond.

Q. How did AEPCO reflect the related ARO liability in deriving its proposed rate base?

A. AEPCO did not reflect the related ARO liability as an offset to rate base. As AEPCO explained in its response to data request STF 1.66(e):

> *AEPCO has not included the liability for Asset Retirement Obligations in its rate base because AEPCO is a non-profit cooperative whose revenue requirement is driven primarily by expense coverage and adequate TIER and DSC coverages.*

Q. Is the Commission committed to using financial accounting such as SFAS 143 for rate-making purposes?

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

Q. What is Staff recommending?

A. Staff recommends decreasing plant in service by $1,092,679 as shown on Attachment RCS-2, Schedule B-6. Staff also recommends no change in the rate-making treatment of retirements with legal obligations.

Q. Is there a related adjustment to operating expenses?

A. Yes. Staff adjustment C-5 removes ARO-related Depreciation Expense and Accretion Expense.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Schedule C summarizes Staff's recommended net operating income. Schedule C.1 presents Staff's recommended adjustments to test year revenues and expenses.

Q. Does AEPCO pay income taxes?

A. No. Because AEPCO is a tax-exempt non-profit corporation organized under the provisions of Section 501(c)(12) of the Internal Revenue Code, it does not pay income taxes. Consequently, there is no impact on state and federal income taxes associated with each of the recommended adjustments to operating income.

Q. How does Staff's recommended adjusted net operating income, or margin, compare with AEPCO's request?

A. AEPCO's proposed adjusted test year net operating income is $3.333 million, whereas Staff's recommended adjusted net operating income is $5.232 million.

Each of Staff's recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

AEPCO's Pro Forma Adjustments to Operating Income

Q. Before we discuss Staff's recommended adjustments to operating income, can you briefly review AEPCO's pro forma adjustments?

A. Yes. AEPCO's pro forma adjustments to operating income are summarized on Attachment RCS-2, Schedule A, page 2, on lines 1-15. AEPCO has proposed fourteen pro forma adjustments, which reduce its net income by a total of $12.501 million.

In its April 20, 2010 amended and restated filing, AEPCO withdrew its originally proposed adjustment #11 for increased chemical costs that it projected needing to acquire in order to reduce mercury emissions starting in 2011.

Coal Cost Adjustment. AEPCO's new coal contracts took effect on January 1, 2009. AEPCO adjustment #1 reduced margin by $14.9 million for the impact of the new contracts. This AEPCO adjustment has been accepted, subject to completion of Staff's prudence review.

Labor Cost Increases. AEPCO adjustment #2 increased labor costs and decreased margin by $1.5 million for changes in labor and benefit costs during and subsequent to the test

year. This AEPCO adjustment has been accepted subject to making an offsetting adjustment for a known post-test year work force downsizing that is quantified in Staff adjustment C-1.

Lost Revenue Adjustments for Contract Expirations. AEPCO adjustments #3 and #4 reflect lost revenues related to SRP and City of Mesa contract expirations. The City of Mesa contract expired on December 31, 2008. The SRP contract expires on December 31, 2010. Based on the review conducted to date, these AEPCO adjustments have been accepted; however, this is subject to potential refinement or adjustment when Staff completes its rate design analysis. The rate design analysis typically involves a detailed review of existing and proposed revenues from each customer class, and the preparation of a proof of revenues. Consequently, it is possible that concerns about AEPCO's existing revenues may come to light during the rate design analysis that were not apparent during the revenue requirement analysis.

Expiring purchase power contract. AEPCO's contract to purchase power from Public Service of New Mexico ("PNM") expired on December 31, 2008. AEPCO's pro forma adjustment #5 annualized the impact and increased margin by $4.7 million. This adjustment has been accepted subject to completion of Staff's prudence review of AEPCO's fuel and purchased power.

Additional sales from capacity availability. AEPCO's adjustments #6 and #7 reflect increased revenue resulting from sales made to two member cooperatives, Mohave Electric Cooperative, Inc. ("MEC") and SSVEC, respectively, to increase margins by $5.3 million and $3.97 million, respectively. Based on the review conducted to date, these AEPCO adjustments have been accepted subject to potential refinement or adjustment

when Staff completes its rate design analysis, as noted above in conjunction with AEPCO proposed adjustments #3 and #4.

Coal and purchased power. AEPCO's pro forma adjustment #8 annualizes the effect of the change in resources, to increase net margins by $6.5 million. AEPCO adjustment #12 reduces Southpoint PPA capacity from 35 to 24 MW to reflect the impact of the SRP, Mesa and PNM contracts expiring, increasing net margin by approximately $232,000. AEPCO adjustment #15 synchronizes revenues with Fuel and Purchased Power Adjustor Clause ("FPPAC") costs from other adjustments, increasing net margin by $2.0 million. These adjustments have been accepted subject to completion of Staff's prudence review of AEPCO fuel and purchased power.

Maintenance Outage Expense. AEPCO's pro forma adjustment #9 amortizes outage expense, increasing margin by $2,129,298. This adjustment has been accepted.

SAP Software Amortization. AEPCO's pro forma adjustment #10 proposes to amortize the Systems Applications Products ("SAP") software at AEPCO over a seven-year period, increasing margin by $824,755. This adjustment has been accepted.

Rate Case Cost. AEPCO's adjustment #13 is for an annual allowance of $160,000 for legal and consultant costs for the current AEPCO rate case. While AEPCO's filing characterizes this as the annual amortization of $480,000 of costs for the rate case application over a three-year period, Staff views the $160,000 as a normalized annual expense allowance amount, not an amortization. AEPCO's response to data request STF 1.52 did not provide the detailed itemization that was sought in that request.[10] This

[10] A copy of AEPCO's response to data request STF 1.52 is included in Attachment RCS-3.

amount has therefore been accepted conditionally, pending receipt of additional detail. Staff is also concerned that the $160,000 requested by AEPCO is double the $80,000 amount of rate case cost requested by the related transmission cooperative, SWTC, yet the filings and many of the issues of these two cooperatives are similar.

Interest Expense Annualization. AEPCO's adjustment #14 annualized interest expense to the end of the test period, reducing net margin by $231,000. AEPCO also adjusted principal payments for the test period to reflect extended maturity dates on certain FFB notes that reduced principal payments by $7.3 million. Staff has accepted AEPCO's adjustment to interest expense and has used the same amount of interest on long-term debt and principal payments for purposes of calculating coverage requirements.

Staff Adjustments to Operating Income

Q. Now will you discuss the adjustments to net operating income that are being recommended by Staff?

A. Yes. Each Staff adjustment to AEPCO's net operating income is discussed below in the order appearing on Attachment RCS-2, Schedule C.1.

C-1. Work Force Reduction

Q. Please explain the adjustment for the significant work force reduction made by AEPCO and its related companies.

A. The response to data request STF 2.31 in SWTC's current rate case, Docket No. E-014100A-9-0496, indicates that AEPCO, SWTC and Sierra have made a reduction in work force of seventeen employees. Moreover, AEPCO calculates that the reduction in force will reduce its labor costs by approximately $898,760 on an annual basis. SWTC provided a confidential attachment to its response to data request STF 2.31 showing

details. A copy of that response is also attached for ease of reference in Attachment RCS-3 to my testimony.

Q. What does AEPCO's response to STF 3.1 show?

A. AEPCO's response to data request STF 3.1 shows that AEPCO had identified five material changes from March 31, 2009 through December 31, 2009. It shows that three changes affected test year operating expenses: (1) fuel expense related to new contracts; (2) payroll and pension expense due to wage increases and National Rural Electric Cooperative Association ("NRECA") pension funding requirement increases; and (3) a SAP software capital lease. The response indicates that each of these three changes have in fact been reflected as pro forma adjustments in AEPCO's rate filing in the "C" schedules and are identified there as Coal Price Adjustment, Payroll and Pension Adjustment and SAP Software Amortization Adjustment.

AEPCO's response to data request STF 3.1 states further that changes related to a telephone system capital lease, post-test year plant in service and net debt increases were not included as adjustments because AEPCO believed Staff would not consider such post-test year expenses to be appropriate adjustments.

Q. How has AEPCO requested increases in labor expenses for changes occurring during and subsequent to the test year?

A. For labor costs alone, AEPCO has requested increased expenses of $1,472,532 in its pro forma adjustment #2 for Payroll and RSI Increases.

Q. Should the significant work force change that was identified by SWTC in response to data request STF 2.31 be reflected as pro forma adjustment in setting AEPCO's rates in the current case?

A. Yes, it should. This is a significant change in work force and it significantly impacts AEPCO's proposed labor costs. Reflecting the impact of the work force change would therefore help to mitigate the impact of the other post-test year increases to labor (and other) costs requested by AEPCO. AEPCO's proposed labor costs include the impact of other post-test year changes, but only changes which increased expense (and decreased margin), such as post-test year wage increases that occurred on September 21, 2009 and a post-test year increase in pension costs. To not reflect the offsetting reduction to AEPCO's labor costs related to the known downsizing of the work force would serve to overstate AEPCO's labor cost significantly on a going-forward basis.

Additionally, as noted above, AEPCO's filing includes other significant pro forma adjustments for other items that extend even further beyond the test year ending March 31, 2009, such as changes related to the expiration on December 31, 2010 of AEPCO's sales agreement with SRP.[11]

Q. What is the impact of this adjustment on AEPCO's labor costs and margin?

A. As shown on Attachment RCS-2, this adjustment decreases AEPCO's labor costs by $898,760 and increases margins by a similar amount.

[11] See, e.g., AEPCO's proposed pro forma adjustment #3 (SRP Contract Expiration Adjustment).

Q. Do you have an alternative recommendation if the Commission does not reflect the impact of the significant post-test year work force decrease on AEPCO's labor costs?

A. Yes. If this adjustment to decrease AEPCO's labor costs for the work force downsizing is not reflected in deriving AEPCO's revenue requirement, alternatively, I would recommend that the other post-test year pro forma adjustments requested by AEPCO, which significantly increased expense (and reduced margins) also be rejected. Rejecting AEPCO's proposed pro forma adjustment #2 for Payroll and Retirement Plan Increases would decrease AEPCO's requested expense by $1,472,532, and would increase margins by a similar amount.

C-2. Incentive Compensation

Q. Does AEPCO have an incentive compensation plan?

A. AEPCO's response to data request STF 1.31(d), (e) and (f) and STF 1.45 provided information concerning AEPCO's incentive compensation. Copies of the relevant incentive program plan documents provided by AEPCO in response to that data request are included in Attachment RCS-3.

Q. What trigger mechanisms are provided for in AEPCO's incentive compensation plan?

A. As shown in the documentation provided by AEPCO in response to STF 1.45, the plan has four trigger mechanisms, which must be met or exceeded by AEPCO to open the program to funding. For the 2008 plan, the four trigger mechanisms were:

1. Positive Operating Margin.
2. Times Interest Earned Ratio ("TIER") of 1.10.
3. Debt Service Coverage Ratio ("DSC") of 1.00.
4. An Equivalent Unplanned Outage Factor ("EUOF"), as defined by IEEE Standard 762, equal to or less than the average EUOF of Steam Units 2 & 3 for the previous full five year period for which data is available. The target EUOF

for the 2008 Incentive Plan is 2.2%, based on the average of years 2002 through 2006.

For the 2009 plan, the four trigger mechanisms were:

1. Positive Operating Margin.
2. Times Interest Earned Ratio ("TIER") of 1.80.
3. Debt Service Coverage Ratio ("DSC") of 1.50.
4. An Equivalent Unplanned Outage Factor ("EUOF"), as defined by IEEE Standard 762, equal to or less than the average EUOF of Steam Units 2 & 3 for the previous full five year period for which data is available. The target EUOF for the 2009 Incentive Plan is 2.2%, based on the average of years 2003 through 2007.

Q. How is the AEPCO incentive plan funded?

A. The AEPCO incentive plan is funded subject to a cap each year that has been approved by the Board of Directors, and is to be funded on a 50/50 split from the savings in actual expenses reduced from those forecast in AEPCO's Budget.[12] Additionally, the plan provides that[13]:

> *All triggers must be satisfied and the achievement with respect to the combined goals must be positive, including provision for funding the program, before the Incentive Plan will be funded. Both AEPCO and SWTC will fund the Incentive Plan proportionately.*

Q. Do these plan provisions raise some concerns about inclusion of the incentive compensation expense in rates?

A. The first three triggers AEPCO had for the 2008 plan appear to be minimal targets that would not reflect adequate financial performance by AEPCO. In contrast with those minimal targets for incentive compensation triggers, AEPCO is seeking, and Staff is recommending, much higher levels in the current rate case.

[12] See, e.g., "Funding Amount" section of AEPCO Incentive Plan documents included in Attachment RCS-3.
[13] See, "Introduction" section of AEPCO Incentive Plan documents included in Attachment RCS-3.

Q. What other aspects of the incentive compensation program raise concerns about including an expense amount for that in operating expenses?

A. The funding of the incentive compensation, as described in the plan documents, is to be based upon a 50/50 split of savings in actual expenses reduced from those forecast in the Budget. AEPCO has not demonstrated that its test year expenses reflect such savings. Consequently, including the incentive compensation expense as an operating expense in determining AEPCO's revenue requirement would be questionable.

Q. How much expense did AEPCO incur in the test year for incentive compensation?

A. AEPCO's response to data request STF 1.45 indicates that AEPCO incurred $681,900 of expense for incentive compensation in the test year. No expense for incentive compensation was incurred in 2009.

Q. Why should incentive compensation expense be removed from test year expenses?

A. In addition to the concerns identified above, there is no assurance that the expense levels included in the test year will be repeated in future years. As noted above, AEPCO's response to data request STF 1.45 indicates there was no expense incurred in 2009.

C-3. Charitable Contributions

Q. Please explain the adjustment to remove Charitable Contributions expense.

A. In response to data request STF 1.24, AEPCO identified $79,926 for Charitable Contributions in the test year. As shown on Schedule C-3, the amounts of $79,926 recorded by AEPCO for such Charitable Contributions are being removed from operating expenses. It is not appropriate to include Charitable Contributions in the cost of service for a public utility because donations are not necessary for the provision of utility service.

C-4. Lobbying in Association Dues

Q. Please explain the adjustment to remove lobbying expense in Association Dues.

A. AEPCO pays dues to various industry associations. Some of those associations engage in lobbying activities. The lobbying activities should be charged below-the-line and excluded from the utility's cost of service. During the test year, four of the industry associations to which AEPCO paid dues were engaged in lobbying and advocacy activities. As described in AEPCO's response to data request STF 1.25, Grand Canyon State Electric Cooperative Association ("GCSECA") estimated that 26 percent of its dues go to lobbying and advocacy activities. The NRECA estimate was 24 percent. Consumers United for Rail Equity ("CURE") estimated 80 percent of dues is for lobbying. The Western Coal Traffic League ("WCTL") estimated 20 percent of its budget is for lobbying. Schedule C-4 shows the amounts of dues paid by AEPCO to these organizations, calculates the amount included in the test year based on the information provided in response to data request STF 1.25, and excludes from test year operating expenses the portion of such dues that are related to lobbying and advocacy activities.

Q. While investigating the inclusion of lobbying costs in association dues, did you discover that one of the dues amounts was overstated for the test year?

A. Yes. An additional adjustment to remove $10,000 for WCTL is necessary based on AEPCO's response to STF 1.25, which stated that:

> *"Actual dues are paid in the amount of $10,000 quarterly. However for the test year, $50,000 was paid, such that anadditional $10,000 was inadvertently included in the test year calculation."*

Q. What is the total impact of this adjustment?

A. As shown on Schedule C-4, test year expense is reduced by $112,240 for the portion of GCSECA, NRECA, CURE and WCTL dues related to lobbying, and for AEPCO's inadvertent over-inclusion of an extra $10,000 in the test year for WCTL dues. AEPCO's margin is increased by the same amount of the expense reduction, $112,240.

C-5. Asset Retirement Obligation-Related Expenses

Q. Please explain Staff adjustment C-5.

A. As shown on Attachment RCS-2, Schedule C-5, this adjustment removes $30,536 of Depreciation Expense and $95,184 of Accretion Expense[14], related to AEPCO's accounting for an ARO related to a coal plant ash pond. As previously discussed in conjunction with Staff rate base adjustment B-6, AEPCO has no investment in the ARO asset; consequently, there is no asset cost to be recovered through depreciation. The ARO-related depreciation and accretion expenses are accounting entries that resulted from AEPCO implementing SFAS 143 for financial reporting purposes. In AEPCO's prior rate case, Docket No. E-01773A-04-0528, Staff recommended the removal of the ARO-related depreciation and accretion expense. The removal of these ARO-related expenses in the current case reflects similar removal treatment for ratemaking purposes. In total, operating expense is reduced by $125,720, and net margin increases by that amount.

[14] Accretion Expense is a type of interest expense that is added to the ARO liability annually to account for the time value of money.

Coal Transportation Legal Expenses

Q. Are there any other matters you wish to address as a result of your review of AEPCO's operating expenses?

A. Yes. I would like to address information obtained during the review of AEPCO's operating expenses concerning AEPCO's legal expenses relating to coal transportation issues.

Q. How has AEPCO been pursuing litigation against a railroad relating to the transportation of coal to the Apache Station?

A. As explained in the responses to data request STF 1-64(b) and 1-38(b), AEPCO has been pursuing litigation against BNSF Railway ("BNSF") before the Surface Transportation Board ("STB") relating to the transportation of coal to the Apache Station.

Q. Has AEPCO sought assistance from other utilities in sharing its litigation costs?

A. No. AEPCO's response to data request STF 1-64(b) explains that AEPCO has not sought assistance from other utilities to share in the litigation cost because AEPCO's case before the STB is a matter that concerns only AEPCO and its specific coal and transportation issues. If AEPCO is successful in its STB rate case against BNSF, AEPCO is the only party that will benefit.

Q. Has AEPCO provided a copy of its claim against the railroad?

A. Yes. In response to data request STF 1-64(c), AEPCO provided its claim and four subsequent amendments thereto.

Q. In what other coal transportation litigation is AEPCO involved?

A. AEPCO is also involved in a dispute with Union Pacific Railroad ("UP").

Q. What amount of expense did AEPCO incur in the test year for legal and consulting fees related to matters involving railroad rates and disputes related to the transportation of coal to the Apache Station?

A. AEPCO's response to data request STF 1-38(b) indicates that AEPCO incurred $538,000 for such matters in the test year. AEPCO's supplemental response to data request STF 1-64(a) indicates that these expenses are recorded in account 5300700.

Q. How does that amount compare with AEPCO's expense for similar activities in other years?

A. These costs are listed by year in response to AEPCO's supplemental responses to data requests STF 1-38 and STF 1-64, and have varied widely from year-to-year, from a low of $38,100 in 2006 to a high of $2.8 million in 2009. AEPCO's response to data request STF 2-21 indicates that AEPCO's six month projection for February through July 2010 are $240,000 for legal costs and $590,000 for consulting and other expenses. AEPCO's response to data request STF 2-18 list amounts separately for 2008, 2009 and January 2010 for the STB rate case against BNSF and for the district court lawsuit against UP. AEPCO's test year amount is lower than the actual amount incurred in 2009 and AEPCO's 2010 projection, and is well within the range of AEPCO's expense for similar activities in other years.

Q. How does AEPCO's response to a Staff data request summarize the nature of the litigation that AEPCO is pursuing against the railroads involved in the transportation of coal to the Apache Station?

A. AEPCO's response to data request STF 2-19 provides the following brief summary:

> *AEPCO is in the process of seeking regulatory relief from coal transportation rates imposed by the BNSF Railway (BNSF) and the*

> *Union Pacific Railroad (UP) through the Surface Transportation Board's (STB) Stand Alone Cost Railroad process. This case was filed in December 2008 with opening evidence and argument submitted by AEPCO January 25, 2010. The railroad's reply case is due in May 2010.*
>
> *AEPCO is also involved in litigation with the UP. UP filed a complaint in January 2009 in U.S. District Court against AEPCO. This complaint alleges that AEPCO refuses to recognize a contract for coal transportation from Colorado and Wyoming coal sources. AEPCO contends that no contract was signed and does not exist. This case continues pending settlement discussions.*
>
> *AEPCO is not involved in any dispute or litigation with the coal suppliers.*

Q. How has AEPCO described the status of any settlement discussions in these matters?

A. AEPCO's response to data request STF 2-20 provides the following summary of settlement discussion status:

> *AEPCO has been involved in settlement discussions with both the Union Pacific Railroad (UP) and the BNSF Railway (BNSF). AEPCO is currently engaged in settlement discussions with the UP. While settlement proposals were exchanged between AEPCO and the BNSF, these proposals were rejected by both parties and AEPCO and the BNSF are not currently engaged in settlement discussions.*

Q. Is Staff proposing any adjustment for AEPCO's "coal transportation legal expenses"?

A. Not at this time. AEPCO's test year amount is well within the range of AEPCO's expense for similar activities in other years, and Staff's prudence review of AEPCO's fuel and purchase power procurement, which should include a detailed review of the related coal transportation litigation AEPCO has engaged in with the railroads, has not yet been completed.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)

80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)

R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)

R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)

GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)

Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)

U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)

03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0085	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
Docket No. 09-0319	Illinois-American Water Company (Illinois Commerce Commission)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company
09-0872-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company (Ohio PUC)

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-09-0472
Attachment RCS-2
Staff Accounting Schedules
Accompanying the Direct Testimony of Ralph C. Smith

Schedule	Description	Pages	Page No.	Note
	Revenue Requirement Summary Schedules			
A	Calculation of Revenue Deficiency (Sufficiency)	2	2-3	
B	Adjusted Rate Base	1	4	
B.1	Summary of Adjustments to Rate Base	1	5	
C	Adjusted Net Operating Income	1	6	
C.1	Summary of Net Operating Income Adjustments	1	7	
D	Capital Structure and Cost Rates	1	8	
	Rate Base Adjustments			
B-1	Plant Held for Future Use	1	9	
B-2	Acquisition Adjustment	1	10	
B-3	Accumulated Depreciation - Retirement Work in Progress	1	11	
B-4	Fuel Stock	1	12	
B-5	Deferred Debits	1	13	
B-6	Asset Retirement Obligation	1	14	
	Net Operating Income Adjustments			
C-1	Work Force Reduction	1	15	
C-2	Incentive Compensation	1	16	
C-3	Donations	1	17	
C-4	Lobbying Expense in Association Dues	1	18	
C-5	Asset Retirement Obligation - Depreciation and Accretion Expense	1	19	
	Total Pages (including Contents page)	19		

Arizona Electric Power Cooperative, Inc.
Computation of Increase in Gross Revenue Requireme

Docket No. E-01773A-09-0472
Schedule A
Page 1 of 2

Test Year Ended March 31, 2009

Line No.	Description	Reference	Per AEPCO Test Year Actual (A)	Per AEPCO Test Year Adjusted (B)	Per AEPCO Proposed Rates (C)	Per Staff Test Year Adjusted (D)	Per Staff Proposed Rates (E)
	I. Net Income Summary						
1	Gross Revenue		$ 209,981,784	$ 178,762,679	$ 178,665,925	$ 178,762,679	$ 178,993,693
2	Operating Expenses		$ 183,767,165	$ 164,623,661	$ 164,623,661	$ 162,820,299	$ 162,820,299
3	Electric Operating Income (Margins)	L1 - L2	$ 26,214,619	$ 14,139,018	$ 14,042,264	$ 15,942,380	$ 16,173,394
4	Total Interest & Other Deductions		$ 11,325,919	$ 11,917,826	$ 11,917,826	$ 11,822,642	$ 11,822,642
5	Total Other Non Operating Income		$ 945,315	$ 1,112,155	$ 1,112,155	$ 1,112,155	$ 1,112,155
6	Extraordinary Items		$ -	$ -	$ -	$ -	$ -
7	Net Income (Margins)	L3-L4+L5&6	$ 15,834,015	$ 3,333,347	$ 3,236,593	$ 5,231,893	$ 5,462,907
	II. Times Total Interest Earned (TIER)						
8	Net Income Margins (Loss)	Line 7	$ 15,834,015	$ 3,333,347	$ 3,236,593	$ 5,231,893	$ 5,462,907
9	Interest on Long Term Debt	Note A	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194
10	Sum of Margin and Interest on LTD	L8 + L9	$ 26,646,209	$ 14,145,541	$ 14,048,787	$ 16,044,087	$ 16,275,101
11	Interest on Long Term Debt	L9	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194
12	TIER Achieved	L10 / L11	2.464459	1.308295	1.305894	1.483888	1.505254
13	Required TIER	Note B	1.305894	1.305894	1.305894	1.505254	1.505254
14	Increased (Decreased) Coverage Needed	L13 - L12	-1.158565	-0.002401	0.000000	0.021366	0.000000
15	Increased (Decreased) Revenue Needed	L14 x L9	$ (12,526,627)	$ (25,959)	$ -	$ 231,014	$ -
	III. Debt Service Coverage (DSC)						
16	Net Income Margins (Loss)	Line 7		$ 3,333,347	$ 3,236,593	$ 5,231,893	$ 5,462,907
17	Interest on Long Term Debt	L9		$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194
18	Depreciation & Amortization	Sch C		$ 8,348,168	$ 8,348,168	$ 8,317,632	$ 8,317,632
19	Sum of Above			$ 22,493,709	$ 22,396,955	$ 24,361,719	$ 24,592,733
20	Interest on Long Term Debt	Line 9		$ 10,812,194	$ 10,812,194	$ 10,812,194	$ 10,812,194
21	Principal Payments	Note C		$ 6,754,044	$ 6,754,044	$ 6,754,044	$ 6,754,044
22	Debt Service			$ 17,566,238	$ 17,566,238	$ 17,566,238	$ 17,566,238
23	DSC Achieved	L19 / L22		1.2805080	1.2750001	1.3868490	1.4000
24	Required DSC	Note B		1.2842531	1.2842531	1.4000000	1.4000
25	Increased Coverage Needed			0.0037451	0.0093	0.01315103	-
26	Increased (Decreased) Revenue Needed			$ 65,787	$ 163,366	$ 231,014	$ -
27	Revenue Increase Proposed vs TY Adjusted	Line 1 difference			$ (96,754) Note D Col.C - Col.B		$ 231,014 Col.E - Col.D
	IV. Return on Fair Value Rate Base						
28	Net Income	L7			$ 3,236,593		$ 5,462,907
29	Interest on Long Term Debt	L9			$ 10,812,194		$ 10,812,194
30	Sum of Net Income and Interest on LTD				$ 14,048,787		$ 16,275,101
31	Difference				$ (6,523)		
32	Required Electric Operating Margin				$ 14,042,264 Note D		$ 16,275,101
33	Rate Base (Original Cost and FVRB are Same)	Sch B			$ 231,844,975 Note D		$ 211,802,594
34	Return on Fair Value Rate Base	L32 / L33			6.06% Note D		7.68%

Notes and Source

Col.A-C:
L1-7: AEPCO Schedule A-2, Amended and Revised April 20, 2010
For Column B, also see Attachment RCS-2, Schedule C
Col.D:
L1-7: Schedule C, Col. C
Col.E:
L1-7: Schedule C, Col. E
Notes A-D:
A AEPCO from AEPCO Excel file; Staff from Schedule C, line 12
B Derived from AEPCO Excel file for AEPCO Schedule A-2; Staff per witness Vickroy
For AEPCO also see Company Schedule A-2 (Amended and Restated April 20, 2010) which shows DSC of 1.28 at AEPCO proposed rates.
C AEPCO Excel file detail for AEPCO Schedule A-2

Arizona Electric Power Cooperative, Inc.
Components of Increase in Gross Revenue Requirement

Docket No. E-01773A-09-0472
Schedule A
Page 2 of 2

Test Year Ended March 31, 2009

Line No.	Description	AEPCO Adj. No.	Impact on Income (A)	Impact on Revenue Requirement (B)
	I. AEPCO's Proposed Pro Forma Adjustments			
1	Coal Cost Adjustment	1	$ (14,946,695)	$ 14,946,695
2	Payroll & Pension Adjustments	2	$ (1,472,532)	$ 1,472,532
3	SRP Contract Expiration Adjustment	3	$ (13,210,326)	$ 13,210,326
4	City Of Mesa Contract Expir. Adjustment	4	$ (2,271,204)	$ 2,271,204
5	PRP PPA Contract Expir. Adjustment	5	$ 4,712,636	$ (4,712,636)
6	MEC Add. Sales Adjustment	6	$ 5,303,853	$ (5,303,853)
7	SSVEC Add. Sales Adjustment	7	$ 3,973,995	$ (3,973,995)
8	Arm Coal & Purchased Power Adjustment	8	$ 6,464,788	$ (6,464,788)
9	Maintenance Outage Adjustment	9	$ (2,129,298)	$ 2,129,298
10	SAP Software Amortization Adjustment	10	$ (824,755)	$ 824,755
11	Mercury Control Adjustment	11	$ -	$ -
12	Southpoint PPA Capacity Adjustment	12	$ 232,500	$ (232,500)
13	Rate Case Amortization Adjustment	13	$ (160,000)	$ 160,000
14	Interest Adjustment	14	$ (231,437)	$ 231,437
15	Revenue Synchronization Adjustment	15	$ 2,057,807	$ (2,057,807)
16	Totals		$ (12,500,668)	$ 12,500,668
	II. Components of AEPCO's Requested Revenue Increase			
17	Increase in Revenue Requirement from AEPCO Pro Forma Adjustments			$ 12,500,668
18	Test Year Actual Income		$ 15,834,015	$ 15,834,015
19	Adjusted Test Year Income with AEPCO's Pro Forma Adjustments		$ 3,333,347	$ (3,333,347)
20	Increase in Revenue Requirement from AEPCO Income Deficiency			$ (3,333,347)
21	Margin Requirement requested by AEPCO			$ 3,236,593
22	Revenue Increase Requested by AEPCO - Calculated per Above			$ (96,754)
23	Difference			$ -
24	Revenue Increase Requested by AEPCO per Schedule A, page 1			$ (96,754)
	III. Staff's Proposed Adjustments	Staff Adj. No.		
25	Work Force Reduction	C-1	$ 898,760	$ (898,760)
26	Incentive Compensation	C-2	$ 681,900	$ (681,900)
27	Donations	C-3	$ 79,926	$ (79,926)
28	Lobbying Expense in Association Dues	C-4	$ 112,240	$ (112,240)
29	Asset Retirement Obligation - Depreciation and Accretion Expense	C-5	$ 125,720	$ (125,720)
30				
31				
32	Totals		$ 1,898,546	$ (1,898,546)
33	Adjusted Test Year Income with Staff's Pro Forma Adjustments		$ 5,231,893	L19 + L32
	IV. Components of Staff's Recommended Revenue Increase			
34	Increase (Decrease) in Revenue Requirement from Staff Income Deficiency		Line 33	$ (5,231,893)
35	Margin Requirement Recommended by Staff		Schedule A, p.1	$ 5,462,907
36	Revenue Increase Recommended by Staff - Calculated per Above			$ 231,014
37	Difference			$ -
38	Revenue Increase Recommended by Staff per Schedule A, page 1			$ 231,014

Notes and Source
AEPCO Schedule C-2 and Staff Schedule A, page 1

Arizona Electric Power Cooperative, Inc.
Original Cost Adjusted Rate Base

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B

Line No.	Description	Original Cost As Adjusted by AEPCO (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
1	Gross Utility Plant in Service	$ 399,424,364	$ (1,092,679)	$ 398,331,685
2	Less: Accumulated Depreciation	$ (204,796,249)	$ (3,547,307)	$ (208,343,556)
3	Net Utility Plant in Service	$ 194,628,115	$ (4,639,986)	$ 189,988,129
4	Customer Advances for Construction	$ -	$ -	$ -
5	Contributions in Aid of Construction	$ -	$ -	$ -
6	Allowance for Working Capital - Fuel and M&S	$ 21,814,465	$ -	$ 21,814,465
7	Plant Held for Future Use	$ 2,551,631	$ (2,551,631)	$ -
8	Deferred Debits	$ 12,850,764	$ (12,850,764)	$ -
9	Total Rate Base	$ 231,844,975	$ (20,042,381)	$ 211,802,594

Notes and Source

Col. A: Arizona Electric Power Cooperative, Inc. filing, Schedule B-1, Amended and Resetated April 20, 2010

Arizona Electric Power Cooperative, Inc.
Summary of Rate Base Adjustments

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B.1
Page 1 of 1

Line No.	Description	Staff Adjustments	Plant Held for Future Use	Acquisition Adjustment	Accumulated Depreciation - Retirement Work in Progress	Fuel Stock	Deferred Debits	Asset Retirement Obligation
			B-1	B-2	B-3	B-4	B-5	B-6
1	Gross Utility Plant in Service	$ (1,092,679)		$ -				$ (1,092,679)
2	Less: Accumulated Depreciation	$ (3,547,307)			$ (3,547,307)			
3	Net Utility Plant in Service	$ (4,639,986)	$ -	$ -	$ (3,547,307)	$ -	$ -	$ (1,092,679)
4	Customer Advances for Construction	$ -						
5	Contributions in Aid of Construction	$ -						
6	Allowance for Working Capital	$ -				$ -		
7	Plant Held for Future Use	$ (2,551,631)	$ (2,551,631)					
8	Deferred Debits	$ (12,850,764)					$ (12,850,764)	
9	Total Rate Base	$ (20,042,381)	$ (2,551,631)	$ -	$ (3,547,307)	$ -	$ (12,850,764)	$ (1,092,679)

Arizona Electric Power Cooperative, Inc.
Adjusted Net Operating Income

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C
Page 1 of 1

Line No.	Description	As Adjusted by AEPCO (A)	Staff Adjustments (B)	As Adjusted by Staff (C)	Staff Proposed Changes (D)	Staff Recommended (E)
	Operating Revenues					
1	Class A Revenues	$ 125,199,347	$ -	$ 125,199,347	$ 224,153	$ 125,423,500
2	Fuel Adjustment	$ 41,419,292	$ -	$ 41,419,292		$ 41,419,292
3	Non-Firm, Non-Member, Non-Class A	$ 8,620,097	$ -	$ 8,620,097	$ 6,861	$ 8,626,958
4	Total Electric Revenue	$ 175,238,736	$ -	$ 175,238,736	$ 231,014	$ 175,469,750
5	Other Operating Revenue	$ 3,523,943	$ -	$ 3,523,943		$ 3,523,943
6	**Total Operating Revenue**	$ 178,762,679	$ -	$ 178,762,679	$ 231,014	$ 178,993,693
	Operating Expenses					
7	Operations & Maintenance	$ 153,342,150	$ (1,772,826)	$ 151,569,324		$ 151,569,324
8	Depreciation & Amortization	$ 8,348,168	$ (30,536)	$ 8,317,632		$ 8,317,632
9	Other Taxes	$ 2,933,343	$ -	$ 2,933,343		$ 2,933,343
10	**Total Operating Expenses**	$ 164,623,661	$ (1,803,362)	$ 162,820,299	$ -	$ 162,820,299
11	**Operating Income (Margins)**	$ 14,139,018	$ 1,803,362	$ 15,942,380	$ 231,014	$ 16,173,394
	Interest & Other Deductions					
12	Long-Term Debt	$ 10,812,194	$ -	$ 10,812,194		$ 10,812,194
13	Interest Charged To Constr	$ (187,816)	$ -	$ (187,816)		$ (187,816)
14	Other Interest Expense	$ 1,142,274	$ (95,184)	$ 1,047,090		$ 1,047,090
15	Other Deductions	$ 151,174		$ 151,174		$ 151,174
16	**Total Interest Expense**	$ 11,917,826	$ (95,184)	$ 11,822,642	$ -	$ 11,822,642
17	**Margin After Interest Expense**	$ 2,221,192	$ 1,898,546	$ 4,119,738	$ 231,014	$ 4,350,752
18	Other Nonoperating Income	$ 1,112,155	$ -	$ 1,112,155		$ 1,112,155
19	**Net Income (Margins)**	$ 3,333,347	$ 1,898,546	$ 5,231,893	$ 231,014	$ 5,462,907

Notes and Source

Col. A: Arizona Electric Power Cooperative, Inc. filing, Schedule C-1, pages 3 and 4, Amended and Restated 4/20/2010
Col. B: Staff Schedule C.1
Col.C: Cols. A + B
Col. D, line 4: Staff Schedule A, Column D, line 26

		Existing Revenue	Increase	Percent Increase
20	Percentage increase over revenues at current rates, from line 6, Total Operating Revenue	$ 178,762,679	$ 231,014	0.13%

Arizona Electric Power Cooperative, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C.1
Page 1 of 1

Line No.	Description	Staff Adjustments	Work Force Reduction	Incentive Compensation	Donations	Lobbying Expense in Association Dues	Asset Retirement Obligation - Depreciation and Accretion
			C-1	C-2	C-3	C-4	C-5
	Operating Revenues						
1	Class A Revenues	$ -					
2	Fuel Adjustment	$ -					
3	Non-Firm, Non-Member, Non-Class A	$ -					
4	Total Electric Revenue	$ -	$ -	$ -	$ -	$ -	$ -
5	Other Operating Revenue	$ -					
6	**Total Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses:						
7	Operations & Maintenance	$ (1,772,826)	$ (898,760)	$ (681,900)	$ (79,926)	$ (112,240)	
8	Depreciation & Amortization	$ (30,536)					$ (30,536)
9	Other Taxes	$ -					
10	Total Operating Expenses	$ (1,803,362)	$ (898,760)	$ (681,900)	$ (79,926)	$ (112,240)	$ (30,536)
11	Operating Income (Margins)	$ 1,803,362	$ 898,760	$ 681,900	$ 79,926	$ 112,240	$ 30,536
	Interest & Other Deductions:						
12	Long-Term Debt	$ -					
13	Interest Charged To Constr	$ -					
14	Other Interest Expense	$ (95,184)					$ (95,184)
15	Other Deductions	$ -					
16	Total Interest Expense	$ (95,184)	$ -	$ -	$ -	$ -	$ (95,184)
17	Margin After Interest Expense	$ 1,898,546	$ 898,760	$ 681,900	$ 79,926	$ 112,240	$ 125,720
18	Other Nonoperating Income	$ -					$ -
19	Net Income (Margins)	$ 1,898,546	$ 898,760	$ 681,900	$ 79,926	$ 112,240	$ 125,720

Arizona Electric Power Cooperative, Inc.
Capital Structure & Cost Rates

Docket No. E-01773A-09-0472
Schedule D
Page 1 of 1

Test Year Ended March 31, 2009

Line No.	Capital Source	Capitalization Amount	Capitalization Percent	Capitalization Debt Only Percent	Cost Rate	Weighted Average Cost of Capital	Annualized Cost With Short Term Debt	Annualized Cost Without Short Term Debt
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
	I. AEPCO Proposed							
1	Short-Term Debt	$ 15,851,384	5.88%	8.17%	0.350%	0.029%	$ 55,480	
2	Long-Term Debt	$ 178,093,188	66.01%	91.83%	5.570%	5.115%	$ 9,919,791	$ 9,919,791
3	Margins and Equity	$ 75,866,848	28.12%			0.000%	$ -	$ -
4	Total Capital	$ 269,811,420	100.00%	100.00%		5.144%	$ 9,975,271	$ 9,919,791
	II. Staff Proposed							
5	Short-Term Debt	$ 15,851,384	5.88%	8.17%	0.350%	0.029%	$ 55,480 (a)	
6	Long-Term Debt	$ 178,093,188	66.01%	91.83%	5.570%	5.115%	$ 9,919,791 (a)	$ 9,919,791 (a)
7	Margins and Equity	$ 75,866,848	28.12%			0.000%	$ -	$ -
8	Total Capital	$ 269,811,420	100.00%	100.00%		5.144%	$ 9,975,271	$ 9,919,791
9	Difference					0.00%		$ -

Notes and Source

Lines 1-4 taken from Arizona Electric Power Cooperative, Inc. filing, Schedule D-1, Revised Schedule D-2, and AEPCO Schedule A-3, actual test year, 3/31/2009, Amended & Restated, April 20, 2010

Lines 5-8: AEPCO Schedule A-3, actual test year, 3/31/2009, confirmed with Staff witness Randall Vickroy

(a) Staff witness Vickroy is recommending that, prior to determining a final revenue requriement, interest be updated to reflect more current actual information. For purposes of computing the revenue requirement at this time, the amount of Long Term Debt Interest in AEPCO's pro forma adjusted income statement was used.

Arizona Electric Power Cooperative, Inc.
Plant Held for Future Use

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B-1
Page 1 of 1

Line No.	Description	Amount	Reference
1	Plant Held for Future Use	$ (2,551,631)	A&B

Notes and Source

A: AEPCO Filing, Schedule B-1, Line 7 and Schedule E-5, page 2, Line 50
Amended and Restated 4/20/2010

B: AEPCO's responses to STF 1.71 and STF 2-11

Arizona Electric Power Cooperative, Inc.
Acquisition Adjustment

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B-2

Line No.	Description	Amount	Reference
1	Remove Acquisition Adjustment from rate base	$ -	A&B

Notes and Source

A: See AEPCO's response to data request STF 2-11. An amount of $13,238 for an Acquisition Adjustment that AEPCO recorded in Account 114 was inadvertently included by AEPCO in rate base as PHFFU and has been removed in Staff Adjustment B-1. Consequently, no additonal adjustment to separately remove the Acquisition Adjustment is necessary in the current case. AEPCO's response also notes that the Acquisition Adjustment has been fully amortized; thus, there should be no related amount for that Acquisition Adjustment included in rate base.
B: Testimony of Staff witness Ralph Smith

Arizona Electric Power Cooperative, Inc.
Accumulated Depreciation - Retirement Work in Progress

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B-3

Line No.	Description	Amount	Reference
1	Adjust Accumulated Depreciation to remove Retirement Work in Progress from rate base	$ (3,547,307)	A&B

Notes and Source

A: AEPCO Filing, Schedule E-5, page 2 of 4 and Schedule B-2
B: Testimony of Staff witness Ralph Smith

Arizona Electric Power Cooperative, Inc.
Fuel Stock

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B-4
Page 1 of 1

Line No.	Month	AEPCO Filed Month-End Balances (A)	AEPCO Adjusted (B)	AEPCO Month-End Balances (C)	Staff Used (D)	Adjustment (E)
1	March (Prior Yr)			$ 12,670,242		
2	April	$ 12,947,499	$ 12,947,499	$ 12,947,499		
3	May	$ 13,052,341	$ 13,052,341	$ 13,052,341		
4	June	$ 12,202,455	$ 12,202,455	$ 12,202,455		
5	July	$ 13,487,043	$ 13,487,043	$ 13,487,043		
6	August	$ 13,527,247	$ 13,527,247	$ 13,527,247		
7	September	$ 13,493,843	$ 13,493,843	$ 13,493,843		
8	October	$ 11,817,432	$ 11,817,432	$ 11,817,432		
9	November	$ 17,387,542	$ 17,387,542	$ 17,387,542		
10	December	$ 19,099,253	$ 19,099,253	$ 19,099,253		
11	January	$ 19,592,846	$ 19,592,846	$ 19,592,846		
12	February	$ 20,512,638	$ 20,512,638	$ 20,512,638		
13	March	$ 25,281,374	$ 25,281,374	$ 25,281,374		
14	Totals	$ 192,401,513	$ 192,401,513	$ 205,071,755		
15	12-Month Average		$ 16,033,459		$ 16,033,459	$ -

Notes and Source

Cols.A and B: AEPCO Amended & Restated Filing, April 20, 2010, Schedule B-5, page 3
Col.C, line 1: AEPCO Schedule E-1, page 1 of 2, 3/31/2008 amount
Col.D: Staff has accepted AEPCO's proposed Fuel Stock amount pending completion of the prudence review.

Arizona Electric Power Cooperative, Inc.
Deferred Debits

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B-5

Line No.	Month	AEPCO Proposed (A)	Staff Proposed (B)	Adjustment (C)
1	Deferred Debits	$ 12,850,764	$ -	$ (12,850,764)

Notes and Source

Cols.A: AEPCO Amended & Restated Filing, April 20, 2010, Schedule B-1, line 8, and Schedule E-1, page 1, line 18. Also see Attachment RCS-2, Schedule B, line 8.

Arizona Electric Power Cooperative, Inc.
Asset Retirement Obligation

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule B-6

Line No.	Month	Adjustment (A)	Reference
	Plant		
1	ST2 ARO Ash Pond Layers	$ 546,339	See below
2	ST3 ARO Ash Pond Layers	$ 546,340	See below
3	Total ARO in Plant Acquisition Value at 3/31/2009	$ 1,092,679	
4	Adjustment to remove ARO from Plant in Rate Base	$ (1,092,679)	

Notes and Source

Lines 1-3: AEPCO's response to data request STF 2-15

Arizona Electric Power Cooperative, Inc.
Work Force Reduction

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C-1
Page 1 of 1

Line No.	Description	Amount	Reference
1	Payroll	$ (641,970)	See below
2	Benefits	$ (256,790)	See below
3	Net Decrease in Labor Expense	$ (898,760)	

Notes and Source

See SWTC's supplemental response to data request STF 2.31 in Docket No. E-04100A-09-0496

Arizona Electric Power Cooperative, Inc.
Incentive Compensation Expense

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C-2

Line No.	Description	Amount	Reference
1	Incentive Compensation Expense	$ (681,900)	See below

Notes and Source

AEPCO's response to data requests STF 1.45

Arizona Electric Power Cooperative, Inc.
Donations

Docket No. E-01773A-09-0472
Schedule C-3
Page 1 of 1

Test Year Ended March 31, 2009

Line No.	Description	Account	Amount	Reference
	Remove Donations from Test Year			
1	Donations AEPCO recorded in other than below-the-line accounts		$ 79,926	Note A
2	Adjustment to Remove Donations		$ (79,926)	

Notes and Source

[A] AEPCO's response to data request STF 1.24

Arizona Electric Power Cooperative, Inc.
Lobbying Expense in Association Dues

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C-4
Page 1 of 1

Line No.	Description	Account	Membership Dues Paid To Lobbying Organizations	Date Paid	Months of Expense in Test Year	Amount In Test Year	Percent Lobbying	Adjustment
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Grand Canyon State Electric Cooperative Association ("GCSECA")	5910200	$ 161,289	Dec-07	9	$ 120,967		
2		5400930	$ 134,471	Dec-08	3	$ 33,618		
3	Subtotal GCSECA				12	$ 154,585	26%	$ (40,192)
4	National Rural Electric Cooperative ("NRECA")	5910200	$ 55,524	Feb-08	10	$ 46,270		
5		5400930	$ 73,590	Jan-09	2	$ 12,265		
6	Subtotal NRECA				12	$ 58,535	24%	$ (14,048)
7	Consumers United for Rail Equity	5400930	$ 50,000	Jan-09		$ 50,000	80%	$ (40,000)
8	Western Coal Traffic League	5400930	$ 40,000			$ 40,000	20%	$ (8,000)
9	Remove additional $10,000 of WCTL that AEPCO inadvertantly included in test year							$ (10,000)
10	Total							$ (112,240)

Notes and Source

AEPCO Response to STF 1.25

Line 9: AEPCO's response states for WCTL that:
"Actual dues are paid in the amount of $10,000 quarterly. However, for the test year, $50,000 was paid, such that an additional $10,000 was inadvertently included in the test year calculation."

Arizona Electric Power Cooperative, Inc.
Asset Retirement Obligation - Depreciation and Accretion Expense

Test Year Ended March 31, 2009

Docket No. E-01773A-09-0472
Schedule C-5
Page 1 of 1

Line No.	Description	Account	Amount	Reference
	I. ARO Depreciation and Accretion Expense Per AEPCO			
1	Depreciation Expense	5711000	$ 30,536	A
2	Accretion Expense	5840000	$ 95,184	B
3	Total		$ 125,720	
	II. Staff Recommended Amounts for ARO Inclusion in Operating Expenses			
4	Depreciation Expense	5711000	$ -	Testimony
5	Accretion Expense	5840000	$ -	Testimony
6	Total		$ -	
	III. Staff Adjustment for ARO-Related Expenses			
7	Depreciation Expense	5711000	$ (30,536)	
8	Accretion Expense	5840000	$ (95,184)	
9	Total		$ (125,720)	

Notes and Source

A AEPCO response to STF 2-16

	Unit	Monthly Expense	No. of Months	Total
10	ST2	$ 1,212.70	8	$ 9,702
11		$ 1,391.56	4	$ 5,566
12			12	$ 15,268
13	ST3	$ 1,212.70	8	$ 9,702
14		$ 1,391.56	4	$ 5,566
15			12	$ 15,268
16	Total Both Units			$ 30,536

B AEP response to STF 1.66(f), Exhibit A, 2008 ARO Accretion

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-09-0472
Attachment RCS-3
Copies of AEPCO's Responses to Data Requests and Documents Referenced in the Direct Testimony and Schedules of Ralph C. Smith

****Contains Confidential Information****

Data Request/ Document	Subject	Confidential	No. of Pages	Page No.
STF 1.71	Property Held for Future Use - No Current Plans for Construction	No	1	2
STF 2-11	Property Held for Future Use - Fully Amortized Acquisition Adjustment	No	1	3
STF 1.66	Increase in Fuel Inventory; Accounting for an ARO	No	7	4 - 10
STF 2-15	AROs Recorded on Company's Books as of March 31, 2009	No	2	11 - 12
STF 1.52	Rate Case expense	No	1	13
	SWTC's Supplemental Response to Data Request STF 2.31 Regarding Workforce Reduction in Current Docket No. E-01400A-09-0496 (Includes only Confidential Attachment)	Yes	2	14 - 15
STF 3.1	Material Changes Occurred for Company between Period of March 31, 2009 and December 31, 2009	No	1	16
STF 1.31	Incentive Compensation Program - Goals	No	2	17 - 18
STF 1.45	Incentive Compensation (Includes 2008 and 2009 Incentive Compensation Plans)	No	10	19 - 28
STF 1.24	Charitable Contributions made in Test Year	No	2	29 - 30
STF 1.25	Lobbying expenses included in Association dues	No	3	31 - 33
STF 2-16	Depreciation of ARO	No	2	34 - 35
STF 1.64	Coal Transportation Legal Expenses	No	2	36 - 37
STF 1.38	Itemization of Coal Transportation Legal Expenses	No	2	38 - 39
STF 2-21	Total Railroad Litigation Costs	No	1	40
STF 2-18	Accumulation of Total Railroad Litigation Costs	No	1	41
STF 2-19	Railroad Litigation Summaries	No	1	42
STF 2-20	Railroad Litigation Settlement Discussions	No	1	43
	Total Pages Including this Page		43	

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
March 5, 2010

STF 1.71 Refer to Schedule B-1. Please provide a detailed itemization of each of the following items that are included in the Company's proposed rate base:

a. Line 7, plant held for future use. Identify, quantify and describe each component of the PHFFU including when it was originally purchased, the purchase cost and the planned in-service date.
b. Line 8, deferred debits. Identify, quantify and describe each component of the deferred debits. For each component, please also indicate whether it had ever been proposed for inclusion in rate base, and provide the case number where it was addressed.

Respondent: Melanie Pearce, Director of Financial Operations

Response: a. Plant Held for Future Use. A parcel of land was purchased in 2004 for the future site of an office complex. The carrying value of this parcel is $2,538,392.31. At this time there are no plans to begin construction of the office complex.

Supplemental Respondent: Gary E. Pierson, Manager of Financial Services

Supplemental Response to 1.71(b):

b. The Deferred Debits are comprised of the items listed on STF 1.71b, attached. These deferred debits primarily consist of overhaul maintenance costs incurred by AEPCO, which are then deferred over the period of the overhaul cycle. In the preparation of the rate base schedules, AEPCO included deferred debits due to the working capital requirements of funding these expenditures. In the previous rate case, Staff made an adjustment to remove deferred debits in the amount of $1,955,000 from rate base which was accepted by AEPCO. However, at the time of the last rate case, AEPCO was accruing anticipated overhaul costs and therefore did not include them as deferred debits. Accordingly, the deferred debit items at issue in the last rate case did not include overhaul maintenance costs

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
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STF 2-11 In the last AEPCO rate case, E-01773A-04-0528, Staff had identified $13,238 for an Acquisition Adjustment that was in Intangible Plant.

a. Has the Company removed that item from its books? If not, explain fully why not.

Respondent: Gary E. Pierson, Manager of Financial Services

Response: No. In the preparation of Schedule E-5, the balance of the Acquisition Adjustment was inadvertently included with Plant Held for Future Use. However, the Acquisition Adjustment has been fully amortized so the effect of its inclusion in the calculation of rate base is zero. The following is a summary of the balances as of March 31, 2009:

114 Acquisition Adjustment	$13,238
115 Amortization of Acquisition Adjustment	13,238
Net Acquisition Adjustment	$0
105 Plant Held for Future Use	$2,538,392

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
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STF 1.66 Refer to Exhibit GEP-1, Financial Statements for periods ending December 31, 2008 and 2007.

a. Explain why the coal and gas inventory increased from $8.5 million to $19.1 million from 12/31/2007 to 12/31/2008.
b. Please provide an itemization of the components of CWIP at 12/31/08 and 12/31/07.
c. Why has CWIP increased from $3.1 million to $10.1 million?
d. Why has Patronage Capital increased from $25.5 million at 12/31/2007 to $57.2 million at 12/31/2008?
e. How has the Company reflected the liability for Asset Retirement Obligations in rate base?
f. Please explain the Company's accounting for Asset Retirement Obligations and provide the journal entries used to record the amounts on page 3.
g. Referring to page 4, why has Transmission decreased from 2007 to 2008?
h. Referring to page 5, please provide the journal entries in 2007 for the Accrued Overhaul that was related to the $4,353,314.
i. In what accounts (expense and liability) was the Accrued Overhaul recorded?
j. Were there any accounting entries made for Accrued Overhaul subsequent to 12/31/2007? If not, explain fully why not. If so, please provide them.

Respondent: Melanie Pearce, Director of Financial Operations

Response:

a. As explained in the direct testimony of Dirk Minson and Gary Pierson, AEPCO's long-term coal arrangements expired at the end of 2008. While making replacement coal arrangements, AEPCO realized that the post-2008 cost of delivered coal would increase significantly both in terms of supplier rates and railroad transportation charges. Accordingly, in 2008 AEPCO developed a strategy to stockpile additional coal under the then-existing contracts to be saved and used in 2009 and 2010. Without this stockpile, the impact of the increased delivered coal costs described by Mr. Minson and Mr. Pierson would require a greater pro forma adjustment and result in a larger proposed rate increase.

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
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b. *See* the attached spreadsheets for the 2007 and 2008 CWIP detail.

c. The CWIP increase from $3.1 million in 2007 to $20.1 million in 2008 is due primarily to the following project costs:

ST2 Cooling Tower Upgrade ($4,778,000);
ST3 Cooling Tower Upgrade ($5,030,000);
Land Acquisition Water Resource ($4,176,000); and
SAP Software ($3,274,000).

d. Patronage Capital increased from $25.5 million at 12/31/2007 to $57.2 million at 12/31/08 because in 2008 the cooperative allocated the Unallocated Accumulated Net Margins in the amount of $31.7 million as of 12/31/2007 to the Class A members. Included in the $31.7 million was a recognition of an increase in equity of $11.2 million resulting from a change in accounting methodology for overhaul costs from an accrual basis to a deferred basis. (*See* AEPCO's Audited Financial Statements for December 31, 2007).

e. AEPCO has not included the liability for Asset Retirement Obligations in its rate base because AEPCO is a non-profit cooperative whose revenue requirement is driven primarily by expense coverage and adequate TIER and DSC coverages.

f. SFAS No. 143 requires the recognition of an Asset Retirement Obligation ("ARO"), measured at estimated Fair value, for legal obligations related to decommissioning and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. The initial capitalized asset retirement costs are depreciated over the life of the related asset, with the accretion of the ARO liability classified as an operating expense. *See* the attached documents.

g. Transmission Expenses decreased from $25.9 million in 2007 to $18.5 million in 2008 due to Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") electing effective January 2008 to become a partial requirements member of AEPCO. The Commission approved the SSVEC conversion to partial requirements in Decision No. 70105, dated December 21, 2007. As a partial requirement member, SSVEC contracts

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directly with Southwest Transmission Cooperative, Inc, for its transmission services. This is why AEPCO's transmission expense decreased from 2007 to 2008.

h. *See* the attached documents related to the Accrued Overhaul.

i. The Accrued Overhaul was recorded in the following accounts:

5713000 – Overhaul Accrual Major (expense)
5714000 – Overhaul Accrual Minor (expense)
2616000 – Overhaul Accrual (liability)

j. There were no accounting entries made for Accrued Overhaul subsequent to 12/31/07. Beginning January 1, 2007, AEPCO adopted the deferral method of accounting for major and minor overhauls. Accordingly, incurred overhaul costs are deferred and amortized over the overhaul benefit periods based on the operating characteristics and profiles of each generating unit.

Doc.type : SA (G/L account document) Normal document

Doc. Number	100193573	Company code	AEPC	Fiscal year	2008
Doc. date	12/31/2008	Posting date	12/31/2008	Period	12
Ref.doc.	2008 LAYER ARO				
Doc.currency	USD				
Doc.head text	2008 Layer ARO				

Itm	PK	Account	Account short text	Assignment	Tx	Amount	Cost Ctr	Order	Text
1	70	1001250	317200000013 0000			60,091.00			
2	50	2302510	Asset Retirement Obl	20081231		60,091.00-			

Doc.type : SA (G/L account document) Normal document

Doc. Number	100193574	Company code	AEPC	Fiscal year	2008
Doc. date	12/31/2008	Posting date	12/31/2008	Period	12
Ref.doc.	2008 LAYER ARO				
Doc.currency	USD				
Doc.head.text	2008 Layer ARO				

Itm	PK	Account	Account short text	Assignment	Tx	Amount	Cost Ctr	Order	Text
1	70	1001250	317300000013 0000			60,091.00			
2	50	2302510	Asset Retirement Obl	20081231		60,091.00-			

Doc.type (G/L account document) Normal document

Doc. number	100193575	Company code	AEPC	Fiscal year	2008
Doc. date	12/31/2008	Posting date	12/31/2008	Period	12
Ref.doc.	2008 ACCRETION				
Doc.currency	USD				
Doc.head.text	2008 Accretion				

Itm	PK	Account	Account short text	Assignment	Tx	Amount	Cost Ctr	Order	Text
1	40	5840000	Accretion Expense	20081231		7,932.00	600000		1997 Layer - ARO Accretion
2	40	5840000	Accretion Expense	20081231		7,932.00	600000		1998 Layer - ARO Accretion
3	40	5840000	Accretion Expense	20081231		7,932.00	600000		1999 Layer - ARO Accretion
4	40	5840000	Accretion Expense	20081231		7,932.00	600000		2000 Layer - ARO Accretion
5	40	5840000	Accretion Expense	20081231		7,932.00	600000		2001 Layer - ARO Accretion
6	40	5840000	Accretion Expense	20081231		7,932.00	600000		2002 Layer - ARO Accretion
7	40	5840000	Accretion Expense	20081231		7,932.00	600000		2003 Layer - ARO Accretion
8	40	5840000	Accretion Expense	20081231		7,932.00	600000		2004 Layer - ARO Accretion
9	40	5840000	Accretion Expense	20081231		7,932.00	600000		2005 Layer - ARO Accretion
10	40	5840000	Accretion Expense	20081231		7,932.00	600000		2006 Layer - ARO Accretion
11	40	5840000	Accretion Expense	20081231		7,932.00	600000		2007 Layer - ARO Accretion
12	40	5840000	Accretion Expense	20081231		7,932.00	600000		2008 Layer - ARO Accretion
13	50	2302510	Asset Retirement Obl	20081231		95,184.00-			1997-2008 Layer - ARO Accretion

Exhibit A
Arizona Electric Power Cooperative, Inc.
2008 ARO Calculation

Annual Liability Expense

2008 Layer	@	6.600%	Annual	Bal. of the	Depreciation of	Total Annual
	For PFIV calc.	Present Value	Accretion	Liability	PV of ARO	Expense
2008	28	$120,181	$7,932	$128,113	$4,292	$12,224
2009	27	$128,113	$8,455	$136,569	$4,292	$12,748
2010	26	$136,569	$9,014	$145,582	$4,292	$13,306
2011	25	$145,582	$9,608	$155,191	$4,292	$13,901
2012	24	$155,191	$10,243	$165,433	$4,292	$14,535
2013	23	$165,433	$10,919	$176,352	$4,292	$15,211
2014	22	$176,352	$11,639	$187,991	$4,292	$15,931
2015	21	$187,991	$12,407	$200,398	$4,292	$16,700
2016	20	$200,398	$13,226	$213,625	$4,292	$17,518
2017	19	$213,625	$14,099	$227,724	$4,292	$18,391
2018	18	$227,724	$15,030	$242,754	$4,292	$19,322
2019	17	$242,754	$16,022	$258,776	$4,292	$20,314
2020	16	$258,776	$17,079	$275,855	$4,292	$21,371
2021	15	$275,855	$18,206	$294,061	$4,292	$22,499
2022	14	$294,061	$19,408	$313,469	$4,292	$23,700
2023	13	$313,469	$20,689	$334,158	$4,292	$24,981
2024	12	$334,158	$22,054	$356,213	$4,292	$26,347
2025	11	$356,213	$23,510	$379,723	$4,292	$27,802
2026	10	$379,723	$25,062	$404,784	$4,292	$29,354
2027	9	$404,784	$26,716	$431,500	$4,292	$31,008
2028	8	$431,500	$28,479	$459,979	$4,292	$32,771
2029	7	$459,979	$30,359	$490,338	$4,292	$34,651
2030	6	$490,338	$32,362	$522,700	$4,292	$36,654
2031	5	$522,700	$34,498	$557,198	$4,292	$38,790
2032	4	$557,198	$36,775	$593,973	$4,292	$41,067
2033	3	$593,973	$39,202	$633,176	$4,292	$43,494
2034	2	$633,176	$41,790	$674,965	$4,292	$46,082
2035	1	$674,965	$44,548	$719,513	$4,292	$48,840
Total			$599,332		**$120,181**	$719,513

Accretion Expense

		2008 Depreciation	2008 Accretion
Old Ponds	2006	$0	$0
New Ponds	1997	$1,395	$7,932
New Ponds	1998	$1,526	$7,932
New Ponds	1999	$1,669	$7,932
New Ponds	2000	$1,827	$7,932
New Ponds	2001	$2,002	$7,932
New Ponds	2002	$2,195	$7,932
New Ponds	2003	$2,409	$7,932
New Ponds	2004	$2,646	$7,932
New Ponds	2005	$2,908	$7,932
New Ponds	2006	$3,200	$7,932
New Ponds	2007	$3,525	$7,932
New Ponds	2008	$4,292	$7,932
Total		$29,595	**$95,184**

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO SECOND SET OF DATA REQUESTS OF
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Docket No. E-01773A-09-0472
March 5, 2010

STF 2-15 Please identify, by account, any and all Asset Retirement Obligations (AROs) recorded on AEPCO's books as of 3/31/2009 and 3/31/2008.

Respondent: Melanie Pearce, Director of Financial Operations

Response: *See* Attached Spreadsheet.

STF 2-15

Report Date: 12/31/2009
Created On: 2/25/2010

Asset Balances - 01 Book deprec.

CompanyCode AEPC

Balance Sheet Account 1001250

CoCd	Class	APC	Asset	SNo.	Cap.date	Asset description	Acquisition Value 3/31/2008	Acquisition Value 3/31/2009
AEPC	3172	1001250	317200000000	0	1/1/1996	ST2 ARO New Ash Pond 2003 Layer	43,653.50	43,653.50
AEPC	3172	1001250	317200000001	0	1/1/1996	ST2 ARO New Ash Pond 2004 Layer	45,159.50	45,159.50
AEPC	3172	1001250	317200000002	0	1/1/1996	ST2 ARO New Ash Pond 2005 Layer	49,606.00	49,606.00
AEPC	3172	1001250	317200000004	0	1/1/1996	ST2 ARO New Ash Pond 1996 Layer	27,907.50	27,907.50
AEPC	3172	1001250	317200000005	0	1/1/1996	ST2 ARO New Ash Pond 1997 Layer	29,749.50	29,749.50
AEPC	3172	1001250	317200000006	0	1/1/1996	ST2 ARO New Ash Pond 1998 Layer	31,713.00	31,713.00
AEPC	3172	1001250	317200000007	0	1/1/1996	ST2 ARO New Ash Pond 1999 Layer	33,806.00	33,806.00
AEPC	3172	1001250	317200000008	0	1/1/1996	ST2 ARO New Ash Pond 2000 Layer	36,037.00	36,037.00
AEPC	3172	1001250	317200000009	0	1/1/1996	ST2 ARO New Ash Pond 2001 Layer	38,415.50	38,415.50
AEPC	3172	1001250	317200000010	0	1/1/1996	ST2 ARO New Ash Pond 2002 Layer	40,951.00	40,951.00
AEPC	3172	1001250	317200000011	0	1/1/1996	ST2 ARO New Ash Pond 2006 Layer	52,880.00	52,880.00
AEPC	3172	1001250	317200000012	0	1/1/1996	ST2 ARO New Ash Pond 2007 Layer	56,370.00	56,370.00
AEPC	3172	1001250	317200000013	0	12/31/2008	ST2 ARO New Ash Pond 2008 Layer	0.00	60,091.00
							486,248.50	546,339.50
AEPC	3173	1001250	317200000000	0	1/1/1996	ST3 ARO New Ash Pond 2003 Layer	43,653.50	43,653.50
AEPC	3173	1001250	317200000001	0	1/1/1996	ST3 ARO New Ash Pond 2004 Layer	45,159.50	45,159.50
AEPC	3173	1001250	317200000002	0	1/1/1996	ST3 ARO New Ash Pond 2005 Layer	49,606.00	49,606.00
AEPC	3173	1001250	317200000004	0	1/1/1996	ST3 ARO New Ash Pond 1996 Layer	27,907.50	27,907.50
AEPC	3173	1001250	317200000005	0	1/1/1996	ST3 ARO New Ash Pond 1997 Layer	29,749.50	29,749.50
AEPC	3173	1001250	317200000006	0	1/1/1996	ST3 ARO New Ash Pond 1998 Layer	31,713.00	31,713.00
AEPC	3173	1001250	317200000007	0	1/1/1996	ST3 ARO New Ash Pond 1999 Layer	33,806.00	33,806.00
AEPC	3173	1001250	317200000008	0	1/1/1996	ST3 ARO New Ash Pond 2000 Layer	36,037.00	36,037.00
AEPC	3173	1001250	317200000009	0	1/1/1996	ST3 ARO New Ash Pond 2001 Layer	38,415.50	38,415.50
AEPC	3173	1001250	317200000010	0	1/1/1996	ST3 ARO New Ash Pond 2002 Layer	40,951.00	40,951.00
AEPC	3173	1001250	317200000011	0	1/1/1996	ST3 ARO New Ash Pond 2006 Layer	52,880.00	52,880.00
AEPC	3173	1001250	317200000012	0	1/1/1996	ST3 ARO New Ash Pond 2007 Layer	56,370.00	56,370.00
AEPC	3173	1001250	317200000013	0	12/31/2008	ST3 ARO New Ash Pond 2008 Layer	0.00	60,091.00
							486,248.50	546,339.50
							972,497.00	1,092,679.00

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
February 19, 2010

STF 1.52 Rate Case Expense. Provide a detailed itemization of all rate case expense, including labor, benefit and overhead cost for affiliated company employees.

Respondent: Gary Pierson, Manager of Financial Services

Response: AEPCO included a rate case expense adjustment for legal and consultant costs of $160,000. That adjustment was calculated using a total estimated rate case expense of $480,000, which was then amortized over a three-year period. The total rate case expense was based on the legal fees and costs incurred in AEPCO's 2004 rate case and an estimate of rate consultant fees and costs for the current case. AEPCO did not include labor, benefit or overhead cost for affiliated company employees in its rate case expense estimate.

SOUTHWEST TRANSMISSION COOPERATIVE, INC.
RESPONSES TO SECOND SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-04100A-09-0496
May 17, 2010

STF 2.31 Employee Count. List the budgeted and, separately, the actual number of employees, by month, for 2008, 2009 and 2010 to date. If the labor force levels are other than full-time equivalent positions, please provide a separate listing stated in terms of full-time equivalent positions.

Respondent: Emery Silvester, Manager of Administrative Services

Response: See attached Employee Count.

Supplemental Respondent: Gary E. Pierson, Manager of Financial Services

Supplemental Response: Last month, SWTC, AEPCO and Sierra made a reduction in force of seventeen employees. SWTC calculates that the reduction in force will reduce its labor costs by about $730,000 on an annual basis. *See* the attached confidential schedule detailing the calculation of the reduced labor costs, provided pursuant to the Protective Agreement between SWTC and Staff, dated April 12, 2010. Because the reduction in force occurred more than a year after closure of the test period, SWTC has not submitted this matter as an additional pro forma adjustment in supplemental response to STF 2.35. In that regard, SWTC has also not requested adjustments for various increases in certain post-test year expenses similar to the expense increases identified by AEPCO in its response to STF 3.1, a copy of which is attached hereto. SWTC has also had such plant-in-service, net debt and other expense increases post-test year.

Confidential

Arizona Electric Power Cooperative, Inc.
Southwest Transmission Cooperative, Inc.

Reduction in Force Salary Caculation - April 2010

Annual Salary	TOTAL	AEPCO	CAM SWTC	Sierra	$ AEPCO	$ SWTC	Sierra	Total $
$38,169.00	$38,169.00	100.00%	0.00%	0.00%	$38,169.00	$0.00	$0.00	$38,169.00
$63,619.00	$63,619.00	86.65%	12.35%	1.00%	$55,125.86	$7,856.95	$636.19	$63,619.00
$40,709.00	$40,709.00	74.36%	21.64%	4.00%	$30,271.21	$8,809.43	$1,628.36	$40,709.00
$26,723.90	$26,723.90	74.36%	21.64%	4.00%	$19,871.89	$5,783.05	$1,068.96	$26,723.90
$44,959.00	$44,959.00	73.03%	23.97%	3.00%	$32,833.56	$10,776.67	$1,348.77	$44,959.00
$72,948.00	$72,948.00	73.00%	26.00%	1.00%	$53,252.04	$18,966.48	$729.48	$72,948.00
$69,285.00	$69,285.00	73.00%	26.00%	1.00%	$50,578.05	$18,014.10	$692.85	$69,285.00
$99,526.00	$99,526.00	73.00%	26.00%	1.00%	$72,653.98	$25,876.76	$995.26	$99,526.00
$99,357.00	$99,357.00	73.00%	26.00%	1.00%	$72,530.61	$25,832.82	$993.57	$99,357.00
$56,271.00	$56,271.00	67.50%	32.50%	0.00%	$37,982.93	$18,288.08	$0.00	$56,271.00
$99,656.00	$99,656.00	100.00%	0.00%	0.00%	$99,656.00	$0.00	$0.00	$99,656.00
$79,044.00	$79,044.00	100.00%	0.00%	0.00%	$79,044.00	$0.00	$0.00	$79,044.00
$96,077.02	$96,077.02	0.00%	100.00%	0.00%	$0.00	$96,077.02	$0.00	$96,077.02
$89,210.42	$89,210.42	0.00%	100.00%	0.00%	$0.00	$89,210.42	$0.00	$89,210.42
$70,045.00	$70,045.00	0.00%	100.00%	0.00%	$0.00	$70,045.00	$0.00	$70,045.00
$94,813.00	$94,813.00	0.00%	100.00%	0.00%	$0.00	$94,813.00	$0.00	$94,813.00
$31,324.02	$31,324.02	0.00%	100.00%	0.00%	$0.00	$31,324.02	$0.00	$31,324.02
$1,171,736.36	**$1,171,736.36**				**$641,969.13**	**$521,673.79**	**$8,093.44**	**$1,171,736.36**
Labor Overhead Adder					40.00%	40.00%		
Total Pensions and Benefits					**$256,787.65**	**$208,669.52**		
Total RIF Annual Salary and Pensions & Benefits (Proforma Adjustment)					**$898,756.79**	**$730,343.31**		

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO THIRD SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
April 14, 2010

STF 3-1 Please identify and explain changes that have occurred for AEPCO from March 31 through December 31, 2009. (a) For each such change, please identify, quantify and explain whether and how it was recognized in AEPCO's A.A.C. R14-2-103.B Schedules. If not recognized in such schedules, please explain why not.

Respondent: Gary Pierson, Manager of Financial Services

Response: We have identified the following material changes which occurred during the period March 31, 2009 through December 31, 2009:

1) Fuel Expense continued to increase due to the new coal contracts.
2) Payroll and pension expense increased due to wage increases and new NRECA pension funding requirements.
3) Capital Leases
    a) SAP software capital lease - $3.25 million
    b) Telephone System Capital Lease - $900,000
4) Plant in Service increased by approximately $23 million. Major items added during the period included:
    a) Plant Boiler Equipment ST2 - $1.5 million
    b) Plant Boiler Equipment ST3 - $7.6 million
    c) Plant Turbogenerator ST2 & ST3 (Primarily Cooling Tower Replacements) - $10.7 million
    d) GT4 Engine Upgrade - $2.5 million
5) AEPCO had additional net loan draws of approximately $15 million during the nine-month period.

Items 1, 2, and 3(a) were recognized as proforma adjustments in AEPCO's rate filing in the "C" schedules and are identified as Coal Price Adjustment, Payroll & Pension Adjustments and SAP Software Amortization Adjustment.

The Capital Lease, Plant in Service and net debt increases were not included as adjustments, because AEPCO believed Staff would not consider such post-test year expenses to be appropriate adjustments.

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
February 17, 2010**

STF 1.31 Employee Benefits.

a. List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to AEPCO.
b. Specifically identify the cost of any SERP or similar programs directly charged or allocated.
c. State the cost by program, of each retirement program directly charged or allocated.
d. Provide the incentive compensation program financial performance goals for the test year and for calendar years 2008 and 2009.
e. For each incentive compensation program goal, for each year, show the actual results and how it compared with the target.
f. Provide the incentive compensation program in effect for the test year and, if different, for calendar years 2008 and 2009.
g. Show in detail how any special recognition awards recorded in the test year were determined.

Respondent: Emery Silvester, Manager of Administrative Services

Response: *See* attachment STF 1.31a – 401K Plan SPD.
See attachment STF 1.31a – Retirement Plan SPD.
STF 1.31b – N/A. AEPCO has no SERP or similar program.
STF 1.31c – *See* costs listed in the response to STF 1.28 Employee Benefits Expense for the Retirement and 401K program.
STF 1.31d – *See* the Incentive Program (Page 2) provided in response to STF 1.45 for 2008 and 2009 goals.
STF 1.31e – *See* the attached 2008 Incentive Program Goals and Results (the 2009 Goals are the same but the results are still in audit).
STF 1.31f – *See* the Incentive Program provided in response to STF 1.45 for 2008 and 2009.
STF 1.31g – N/A. There were no special recognition awards.

2008 Incentive Program Goals and Results

TeamWorks Incentive Plan 2008: December 31, 2008

AEPCO Triggers

	With Accrual *	Trigger met? Y or N
1. Positive Operating Margin		
Actual Operating Margin, Year-to-date	$16,097,468	Y
2. Times Interest Earned Ratio (TIER) of at least 1.10		
Actual TIER, Year-to-date	2.659	Y
3. Debt Service Coverage Ratio (DSCR) of at least 1.00		
Actual DSCR, Year-to-date	1.332	Y
4. Equivalent Availability Factor (EUOF) of 2.2% or less		
Actual EUOF year-to-date	1.46%	Y

AEPCO Performance Goals & Achievement

	YTD Budget/Goal	YTD Actual Achievement	Achieved Savings	Available Funding **
Non-Fuel Production Operations	$11,188,000	$10,581,718	$606,282	$303,141
Maintenance less Overhauls	$10,522,000	$9,523,265	$998,735	$499,368
Administrative & General Expenses	$9,951,000	$10,161,494	$0	$0
	$31,661,000	$30,266,477	$1,605,017	$802,509
			Maximum Payout	**$681,900**

SWTC Triggers

	With Accrual *	Trigger met? Y or N
1. Positive Net Margins		
Actual Net Margins, Year-to-date	$4,936,128	Y
2. Times Interest Earned Ratio (TIER) of at least 1.10		
Actual TIER, Year-to-date	2.000	Y
3. Debt Service Coverage Ratio (DSCR) of at least 1.00		
Actual DSCR Year-to-date	1.072	Y
4. Circuit Segment Hours Availability Factor (CSHAF) of 99.955% or better		
Actual CSHAF year-to-date	99.976%	Y

SWTC Performance Goals & Achievement

	YTD Budget/Goal	YTD Actual Achievement	Achieved Savings	Available Funding **
Transmission O&M/Systems	$10,539,000	$12,195,808	$0	$0
Administrative & General Expenses	$4,225,000	$4,065,415	$159,585	$79,793
	$14,764,000	$16,261,223	**$159,585**	**$79,793**

Total Available for Funding

AEPCO, YTD**	681,900
SWTC, YTD***	79,793
TOTAL	761,693

*Triggers must remain active with accrual of funding.
**AEPCO Savings are shared 50% to margins 50% to TeamWorks up to a maximum of $681,900
***SWTC Savings are shared 50% to margins 50% to TeamWorks up to a maximum of $318,100

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
February 17, 2010

STF 1.45 Payroll, Incentive Programs. Please provide complete copies of any bonus programs or incentive award programs in effect at the Company for the most recent three years. Identify all incentive and bonus program expense incurred in the test year and for calendar 2008 and 2009. Identify the accounts charged. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in the test year and in calendar 2008 and 2009.

Respondent: Emery Silvester, Manager of Administrative Services

Response: *See* attached STF 1.45 2007 Incentive Program.
See attached STF 1.45 2008 Incentive Program.
See attached STF 1.45 2009 Incentive Program.
See attached STF 1.45 Incentive Plan Expenses.

STF 1.45 2008 Incentive Program

SCHEDULE 1

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

2008 Incentive Program

Effective Date January 1, 2008

INTRODUCTION

All employees that support AEPCO can positively affect the following goals in some way. Looking at the results of the Incentive Plan is a simple way to determine how successfully AEPCO is performing. This Incentive Plan is funded through savings, by reducing actual expenditures in Non-Fuel Production Operation, Production Maintenance, and Administrative and General expenditures for AEPCO, from those forecast in the 2008 Budget. All triggers must be satisfied and the achievement with respect to the combined goals must be positive, including provision for funding the program, before the Incentive Plan will be funded. Both AEPCO and SWTC will fund the Incentive Plan proportionately. The CEO is not included in this incentive plan.

Objectives

1. To encourage and reward employees for progress towards key performance goals identified by the Management team.
2. To reinforce focus on customer service.
3. To foster strong teamwork throughout the Cooperatives.
4. To align the interests of all stakeholders: Cooperatives, customers and employees.

Trigger Mechanisms

Four trigger mechanisms must be met, or exceeded, by AEPCO to open the program to funding:

1. Positive Operating Margin.
2. Times Interest Earned Ratio (TIER) 1.10.
3. Debt Service Coverage Ratio (DSC) 1.00.
4. An Equivalent Unplanned Outage Factor (EUOF), as defined by IEEE Standard 762, equal to or less than the average EUOF of Steam Units 2 & 3 for the previous full five year period for which data is available. The target EUOF for the 2008 Incentive Plan is 2.2%, based on the average of years 2002 through 2006.

Performance Goals

Three performance goals will be combined to serve as the funding mechanism for the 2008 Incentive Plan, as follows:

1. Non-Fuel Production Operations Budget, measured in dollars;
2. Production Maintenance Budget, measured in dollars; and
3. Administrative and General (A&G) Budget, measured in total dollars spent.

Tracking Results

A monthly report will be made, displaying the year-to-date results.

Funding Amount

The Incentive Plan funding cap that has been approved by the AEPCO Board of Directors is $ 681,900, to be funded on a 50/50 split from the savings in actual expenses reduced from those forecast in the Budget.

Allocation Mechanism

The Incentive Plan covers all AEPCO, SWTC and Sierra employees except for the CEO and the Sales and Natural Gas Operations staff. It is funded by AEPCO and SWTC based on the respective amounts of the 2008 Combined Budget Total which are accountable to each. The proportionate amount of the Combined Budget Total for which each Cooperative is responsible is the funding ratio for that Cooperative. The funding ratio is then used to determine the respective incentive fund distribution cap levels for each Cooperative.

The ratio of funding for 2008, and cap levels are as follows:

AEPCO:	68.19%	or	$ 681,900
SWTC:	31.81%	or	$ 318,100
			$1,000,000

Distribution Mechanism

Following activation of their respective triggers, the total available funds for distribution will be calculated for each Cooperative. The calculation will be based upon the number of employees in each cooperative at the time of distribution.

For 2008, the total available funds for distribution will be apportioned according to the following Employee Categories: AEPCO-Designated; SWTC-Designated; and Sierra Shared.

AEPCO-Designated shall consist of the following:
AEPCO Group Employees + Sierra A Group Employees

SWTC-Designated shall consist of the following:
SWTC Group Employees + Sierra Group B Employees

Sierra Shared shall consist of the following:
Sierra C Group and E Group (less CEO) Employees

Personnel in the AEPCO-Designated Category shall have funds allocated to them by AEPCO. Personnel in the SWTC-Designated Category shall have funds allocated to them by SWTC. Personnel in the Sierra Shared Category shall have funds allocated to them by both AEPCO and SWTC.

The funding distribution mechanism operates in several steps, as follows:

1. An employee apportionment ratio is calculated according to the proportion of employees in a category to the overall employee population. The entire incentive fund amount is then preliminarily divided up amongst the employee categories in accordance with the applicable employee apportionment ratios.

2. The actual savings amount for both Cooperatives is divided into an AEPCO Portion and an SWTC Portion. Reduction ratios for the AEPCO-Designated Category and the SWTC-Designated Category are then calculated as the proportion of the Cooperative's Portion to its respective cap level.

3. The AEPCO-Designated and SWTC-Designated Categories' preliminary division of the incentive fund amount is then reduced in accordance with their respective reduction ratios.

4. After allocation to AEPCO, SWTC and Sierra of available funds to be distributed to their AEPCO-Designated and SWTC-Designated employees in accordance with this funding distribution mechanism, the remainder of the actual savings amount shall be allocated to Sierra for distribution to the Sierra Shared employees.

5. If either AEPCO or SWTC fail to trip the trigger for their respective employee categories, then the weight of funding the program for the Sierra Shared category will be borne by the Cooperative achieving its threshold triggers. Employees designated as those of the Cooperative not contributing will not be subsidized by the other Cooperative.

Incentive Plan Funding Goals for 2008

The Incentive Plan funding goal for 2008 is to reduce the actual total combined expenditures attributable to the three discrete Budget categories indicated below:

1. Non-Fuel Production Operations Budget	$ 11,188,000
2. Production Maintenance Budget	$ 10,522,000
3. Administrative and General Budget	$ 9,951,000
Budget Total	$ 31,661,000

A reduction to the combined Budget total of $ 31,661,000 by saving $ 1,363,800, or approximately 4.31% in expenditures, would reach the cap and result in funding the AEPCO Incentive Plan with $ 681,900 for the Incentive Plan and $681,900 remaining with AEPCO, for a 50/50 split of the savings. Any smaller reductions from these Budget amounts would likewise be split 50/50 between the Incentive Plan and AEPCO, providing funding for the Incentive Plan at year end at a lower amount, but still sharing the savings and the results of employee efforts.

Non-Fuel Production Operations Budget

Objective: Achieve a reduction from the 2008 Non-Fuel Production Operations Budget for all Apache Station generation units. The 2008 Non-Fuel Production Operation Budget is$ 11,188,000, as found in the published operating statement. Results will be reported monthly in the Board financial report.

Production Maintenance Budget

Objective: Achieve a reduction from the 2008 Production Maintenance Budget, which represents total maintenance budget dollars, less overhaul budget accruals and/or deferrals. The 2008 Production Maintenance Budget is $ 10,522,000 for all Apache Station generating units in 2008. Results will be reported monthly in the Board financial report.

Administrative & General Budget

Objective: Achieve a reduction of the 2008 Administrative and General Budget. The 2008 Administrative and General Budget is $ 9,951,000, as reflected in the Budget. Results will be reported monthly in the Board financial report.

STF 1.45 2009 Incentive Program

SCHEDULE 1

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

2009 Incentive Program

Effective Date January 1, 2009

INTRODUCTION

All employees that support AEPCO can positively affect the following goals in some way. Looking at the results of the Incentive Plan is a simple way to determine how successfully AEPCO is performing. This Incentive Plan is funded through savings, by reducing actual expenditures in Non-Fuel Production Operation, Production Maintenance, and Administrative and General expenditures for AEPCO, from those forecast in the 2009 Budget. All triggers must be satisfied and the achievement with respect to the combined goals must be positive, including provision for funding the program, before the Incentive Plan will be funded. Both AEPCO and SWTC will fund the Incentive Plan proportionately. The CEO is not included in this incentive plan.

Objectives

1. To encourage and reward employees for progress towards key performance goals identified by the Management team.
2. To reinforce focus on customer service.
3. To foster strong teamwork throughout the Cooperatives.
4. To align the interests of all stakeholders: Cooperatives, customers and employees.

Trigger Mechanisms

Four trigger mechanisms must be met, or exceeded, by AEPCO to open the program to funding:

1. Positive Operating Margin.
2. Times Interest Earned Ratio (TIER)1.80.
3. Debt Service Coverage Ratio (DSC) 1.50.
4. An Equivalent Unplanned Outage Factor (EUOF), as defined by IEEE Standard 762, equal to or less than the average EUOF of Steam Units 2 & 3 for the previous full five year period for which data is available. The target EUOF for the 2009 Incentive Plan is 2.2%, based on the average of years 2003 through 2007.

Performance Goals

Three performance goals will be combined to serve as the funding mechanism for the 2009 Incentive Plan, as follows:

1. Non-Fuel Production Operations Budget, measured in dollars;
2. Production Maintenance Budget, measured in dollars; and
3. Administrative and General (A&G) Budget, measured in total dollars spent.

Tracking Results

A monthly report will be made, displaying the year-to-date results.

Funding Amount

The Incentive Plan funding cap that has been approved by the AEPCO Board of Directors is $670,000, to be funded on a 50/50 split from the savings in actual expenses reduced from those forecast in the Budget.

Allocation Mechanism

The Incentive Plan covers all AEPCO, SWTC and Sierra employees except for the CEO and the Sales and Natural Gas Operations staff. It is funded by AEPCO and SWTC based on the respective amounts of the 2009 Combined Budget Total which are accountable to each. The proportionate amount of the Combined Budget Total for which each Cooperative is responsible is the funding ratio for that Cooperative. The funding ratio is then used to determine the respective incentive fund distribution cap levels for each Cooperative.

The ratio of funding for 2009, and cap levels are as follows:

AEPCO:	67%	or	$ 670,000
SWTC:	33%	or	$ 330,000
			$1,000,000

Distribution Mechanism

Following activation of their respective triggers, the total available funds for distribution will be calculated for each Cooperative. The calculation will be based upon the number of employees in each cooperative at the time of distribution.

For 2009, the total available funds for distribution will be apportioned according to the following Employee Categories: AEPCO-Designated; SWTC-Designated; and Sierra Shared.

AEPCO-Designated shall consist of the following:
AEPCO Group Employees + Sierra A Group Employees

SWTC-Designated shall consist of the following:
SWTC Group Employees + Sierra Group B Employees

Sierra Shared shall consist of the following:
Sierra C Group and E Group (less CEO) Employees

Personnel in the AEPCO-Designated Category shall have funds allocated to them by AEPCO. Personnel in the SWTC-Designated Category shall have funds allocated to them by SWTC. Personnel in the Sierra Shared Category shall have funds allocated to them by both AEPCO and SWTC.

The funding distribution mechanism operates in several steps, as follows:

1. An employee apportionment ratio is calculated according to the proportion of employees in a category to the overall employee population. The entire incentive fund amount is then preliminarily divided up amongst the employee categories in accordance with the applicable employee apportionment ratios.

2. The actual savings amount for both Cooperatives is divided into an AEPCO Portion and an SWTC Portion. Reduction ratios for the AEPCO-Designated Category and the SWTC-Designated Category are then calculated as the proportion of the Cooperative's Portion to its respective cap level.

3. The AEPCO-Designated and SWTC-Designated Categories' preliminary division of the incentive fund amount is then reduced in accordance with their respective reduction ratios.

4. After allocation to AEPCO, SWTC and Sierra of available funds to be distributed to their AEPCO-Designated and SWTC-Designated employees in accordance with this funding distribution mechanism, the remainder of the actual savings amount shall be allocated to Sierra for distribution to the Sierra Shared employees.

5. If either AEPCO or SWTC fail to trip the trigger for their respective employee categories, then the weight of funding the program for the Sierra Shared category will be borne by the Cooperative achieving its threshold triggers. Employees designated as those of the Cooperative not contributing will not be subsidized by the other Cooperative.

Incentive Plan Funding Goals for 2009

The Incentive Plan funding goal for 2009 is to reduce the actual total combined expenditures attributable to the three discrete Budget categories indicated below:

1. Non-Fuel Production Operations Budget	$ 12,280,000
2. Production Maintenance Budget	$ 10,224,000
3. Administrative and General Budget	$ 12,164,000
Budget Total	$ 34,668,000

A reduction to the combined Budget total of $ 34,668,000 by saving $1,340,000, or approximately 3.90% in expenditures, would reach the cap and result in funding the AEPCO Incentive Plan with $ 670,000 and $670,000 remaining with AEPCO, for a 50/50 split of the savings. Any smaller reductions from these Budget amounts would likewise be split 50/50 between the Incentive Plan and AEPCO, providing funding for the Incentive Plan at year end at a lower amount, but still sharing the savings and the results of employee efforts.

Non-Fuel Production Operations Budget

Objective: Achieve a reduction from the 2009 Non-Fuel Production Operations Budget for all Apache Station generation units. The 2009 Non-Fuel Production Operation Budget is$12,280,000, as found in the published operating statement. Results will be reported monthly in the Board financial report.

Production Maintenance Budget

Objective: Achieve a reduction from the 2009 Production Maintenance Budget, which represents total maintenance budget dollars, less overhaul budget accruals and/or deferrals. The 2009 Production Maintenance Budget is $ 10,224,000 for all Apache Station generating units in 2009. Results will be reported monthly in the Board financial report.

Administrative & General Budget

Objective: Achieve a reduction of the 2009 Administrative and General Budget. The 2009 Administrative and General Budget is $12,164,000, as reflected in the Budget. Results will be reported monthly in the Board financial report.

STF 1.45 Payroll Incentive Programs

Teamworks Incentive Plan

	AEPCO	
2008	$681,900	**This amount is the only expense incurred during the test period**
2009	$0.00	**No expense has yet been incurred for 2009 (audit still in progress)**

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
February 12, 2010

STF 1.24 Contributions. For the test year, please list all contributions for charitable and political purposes, if any, recorded in accounts other than below the line. Indicate the amount of the expenditure, the recipient of the contribution, and the specific account charged. Also identify for the test year the amounts of contributions for charitable and political purposes charged to the Company from affiliates in accounts other than below the line accounts.

Respondent: Melanie Pearce, Director of Financial Operations

Response: *See* the attached spreadsheet.

Arizona Electric Power Cooperative, Inc.
Donations
For the Test Year Ended March 31, 2009

		Amount
National G & T Managers Associations	$	31,981.00
Touchstone Energy Events Sponsorship - Trico Electric Coop	$	5,000.00
Touchstone Energy CFL Education Kits	$	89.92
El Tour de Tucson Official Energy Sponsor	$	1,500.00
Boy Scouts Golf Fundraising Event	$	5,000.00
2008 U of A Ag Cat Open	$	6,000.00
2008 Sierra Vista Open	$	5,000.00
Southern Arizona Junior Golf Association Invitational Tournament	$	1,000.00
Touchstone Energy Events Sponsorship - Trico Electric Coop	$	5,000.00
NET Conference G & T Alliance	$	6,000.00
Touchstone Energy Events Sponsorship - Duncan Valley Class of 2008	$	5,000.00
Boy Scouts - Plastic Gift Bags	$	75.59
Table Throws	$	2,263.18
NRECA	$	(4,234.00)
Mohave Electric Coop - Annual Community Days	$	5,000.00
Donation - Banner on Gym Wall - St David Public Schools	$	250.00
Touchstone Energy Events Sponsorship - Graham County Electric Coop	$	5,000.00
	$	79,925.69

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO FIRST SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-09-0472
March 5, 2010**

STF 1.25 Dues, Industry Associations. Please list all membership payments made to industry associations (e.g., National Rural Electric Cooperative Association, etc.) requested for recovery during the test year. Identify the account into which such amounts are charged.

a. State the purpose and objective of each organization listed.
b. Provide descriptive material the Company has concerning each organization's financial statements, annual budget and activities.
c. Do any of the organizations listed engage in lobbying or advocacy activities, attempts to influence public opinion, institutional or image-building advertising? If so, list each organization which engages in such activities, and state the Company's best estimate of the portion of the organization's expenses devoted to such activities. Explain and show how such estimates were derived. State if the Company has included the portions of dues related to such activities in the test year.

Respondent: Melanie Pearce, Director of Financial Operations

Response: *See* the attached spreadsheet. A supplemental response will be provided to (b) and (c).

Supplemental Response: *See* the attached revised association dues spreadsheet.

a. *See* the attached documentation regarding GSECA, NRECA, and Touchstone Energy.

Consumer's United for Rail Equity (CURE): CURE is a coalition of freight rail customers seeking changes in federal law and policy that would require railroads to provide more competitive pricing and reliable service. CURE's goal is to hold railroads accountable to their customers and the public. An umbrella membership organization, CURE includes large trade associations that represent more than 3,500 electric, utility, chemical, manufacturing and forest and paper companies and their customers.

Western Coal Traffic League (WCTL): WCTL is a voluntary association comprised of consumers of coal mined in the western United States. WCTL members purchase over 120 million tons of coal annually. WCTL's principal mission is to encourage Congress, executive

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departments, administrative agencies, and the courts to establish and apply standards that promote the lowest delivered costs for its members' coal purchases.

Additional information may be obtained at gseca.org, nreca.coop, touchstoneenergy.cooperative.com, railcure.org, opensecrets.org.

b. *See* the attached annual reports for GSECA and NRECA. Similar documents are not available to AEPCO concerning Touchstone Energy, CURE, and WCTL.

c. GSECA, NRECA, CURE, and WCTL engage in lobbying and advocacy activities. GSECA estimates that 26% of its dues go to lobbying and advocacy activities. This information was provided by Nicolle Migliaccio of GSECA. NRECA estimates 24%. This information was provided by Tiffany Jaggers of NRECA. CURE estimates that 80% of its dues go to lobbying. This information was provided by a member of Van Ness Feldman, PC. WCTL estimates that last year approximately 20% of its budget went to lobbying. This estimate was provided by Pete Pfohl of WCTL

Arizona Electric Power Cooperative, Inc.
Association Dues

Memberships	Amount Paid	Date Paid	Monthly Allocation	G/L Number
GCSECA	161,288.85	Dec-07	13,440.73	5910200 *
NRECA	55,524.00	Feb-08	4,627.00	5910200 *
Touchstone	121,070.00	Jan-08	10,089.16	5910200 *
GCSECA	134,470.98	Dec-08	11,205.92	5400930 *
NRECA	73,590.24	Jan-09	6,132.52	5400930 *
Touchstone	125,500.00	Mar-09	10,458.33	5400930 *
Consumers United for Rail Equity	50,000.00	Jan-09	-	5400930
Western Coal Traffic League	50,000.00	**	-	5400930

* These are amortized over 12 months and only the portion of the dues attributable to the 12 months in the test year are included in AEPCO's calculation.

** Actual dues are paid in the amount of $10,000 quarterly. However for the test year, $50,000 was paid, such that an additional $10,000 was inadvertently included in the test year calculation.

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STF 2-16 During the test year, did AEPCO record any amounts in any income statement accounts related to AROs and/or Statement of Financial Accounting Standards No. 143 (FAS 143)? If not, explain fully why not. If so, please identify, quantify and explain the amounts by account.

Respondent: Melanie Pearce, Director of Financial Operations

Response: *See* the attached spreadsheet.

STF 2-16

Arizona Electric Power Cooperative, Inc.
Asset Retirment Obligations
For the Test Year end March 31, 2009

	Accumulated Depreciation ARO - ST2	Depreciation Expense	Accumulated Depreciation ARO - ST3	Depreciation Expense
	1081210	**5711000**	**1081310**	**5711000**
Apr-08	(1,212.69)	1,212.69	(1,212.69)	1,212.69
May-08	(1,212.72)	1,212.72	(1,212.72)	1,212.72
Jun-08	(1,212.75)	1,212.75	(1,212.75)	1,212.75
Jul-08	(1,212.65)	1,212.65	(1,212.65)	1,212.65
Aug-08	(1,212.72)	1,212.72	(1,212.72)	1,212.72
Sep-08	(1,212.69)	1,212.69	(1,212.69)	1,212.69
Oct-08	(1,212.74)	1,212.74	(1,212.74)	1,212.74
Nov-08	(1,212.72)	1,212.72	(1,212.72)	1,212.72
Dec-08	(1,391.52)	1,391.52	(1,391.52)	1,391.52
Jan-09	(1,391.56)	1,391.56	(1,391.56)	1,391.56
Feb-09	(1,391.56)	1,391.56	(1,391.56)	1,391.56
Mar-09	(1,391.56)	1,391.56	(1,391.56)	1,391.56
		15,267.88		15,267.88

30,535.76

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STF 1.64 Refer to the testimony of Mr. Pierson at page 8.

a. Please identify all "coal legal expenses" by account for the test year used in the last rate case and each subsequent year.
b. Has the Company sought any similarly situated other utilities to assist it and share the cost of litigation for the matters being pursued against the railroad(s)? If not, explain fully why not. If so, please explain fully.
c. Please provide a copy of the claim against BN that the Company has filed at the STB concerning rail transportation rates. Include each amendment that has been made to the claim.

Respondent: Gary Grim, Sr. Vice President & Chief Operating Officer

Response:

a. We are encountering difficulties assembling the requested data due to our conversion after the last rate case from the JDE to SAP accounting system. A supplemental response will be provided.

b. AEPCO has not sought assistance from any other utilities to share in the cost of its litigation efforts for the matters being pursued against the railroad(s). AEPCO's rate case before the Surface Transportation Board is a matter that concerns only AEPCO and its specific coal and transportation issues. If AEPCO is successful in its rate case, AEPCO is the only party that will benefit.

c. *See* the attached claim and four subsequent amendments thereto.

Supplemental Respondent: Melanie Pearce, Director of Financial Operations

Supplemental Response to 1.64(a):

a.

2004	$982,000
2005	$66,600
2006	$38,100
2007	$92,100
2008	$292,000
2009	$2,800,000

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These expenses are found in account number 5300700.

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STF 1.38 Legal Expense.

a. Please itemize the amount of non-rate case legal expense for the test year. For each distinct item over $20,000, show payee, amount, account, and indicate what services were performed and what the subject matter of the services was.
b. Please identify for the test year, and for the calendar years, 2006 through 2009, by account, all legal and consulting costs related to matters involving railroad rates and any disputes about railroad rates related to transportation of coal to the Apache Plant.

Respondent: Dwight M. Whitley, Jr., Corporate Counsel

Response: a. AEPCO's total legal expenses, excluding rate-case expenses, for the test year were $1,376,086.92. Please see Attachment 1.38(a) for a summary of AEPCO's total legal expenses, excluding rate case expenses, for the test year.

b. AEPCO's legal and consulting costs, for calendar years 2006 through 2009 and the test year, related to matters involving railroad rates and any disputes about railroad rates related to transportation of coal to the Apache Station are as follows:

2006	$35,538.68
2007	$92,101.60
2008	$278,669.24
2009	$2,804,789.68
Test year	$524,694.24

Supplemental Response:

a. AEPCO's total legal expenses, excluding rate-case expenses, for the test year were approximately $1,394,000. *See* the revised Attachment 1.38(a) for a summary of AEPCO's total legal expenses, excluding rate case expenses, for the test year.

b. AEPCO's legal and consulting costs, for calendar years 2006 through 2009 and the test year, related to matters involving railroad rates and any disputes about railroad rates related to transportation of coal to the Apache Station are as follows:

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2006	$38,100
2007	$92,100
2008	$292,000
2009	$2,800,000
Test year	$538,000

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STF 2-21 What amount of total litigation cost does AEPCO project to incur with respect to the matters in dispute with the railroad and coal suppliers?

Respondent: Dwight M. Whitley Jr., Corporate Counsel

Response: The six month projection for February 2010 through July 2010 is $240,000 for legal costs and $590,000 for consulting and other expenses. No other information is provided after the six month projection.

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STF 2-18 Please list the total amount AEPCO has spent through 1/31/2010 on the coal and railroad litigation. Please show the accumulation of the total amount by year, broken out between (1) legal, (2) consulting and (3) other.

Respondent: Dwight M. Whitley Jr., Corporate Counsel

Response: AEPCO does not account separately for consulting and "other" expenses related to litigation. These costs are booked together with the litigation legal fees.

The accumulated totals, by year, for the matter pending before the Surface Transportation Board (as described in the response to STF 2-19) are as follows: $79,800 (2008); $2,759,300 (2009); and $602,800 (through January 2010).

The accumulated totals, by year, for the district court lawsuit against Union Pacific Railroad (as described in the response to STF 2-19) are as follows: $35,000 (2009); and $1,800 (through January 2010).

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STF 2-19 Please provide a brief summary describing the issues in dispute and the current status of the litigation with the railroad and with any coal suppliers.

Respondent: Dwight M. Whitley, Jr., Corporate Counsel

Response: AEPCO is in the process of seeking regulatory relief from coal transportation rates imposed by the BNSF Railway (BNSF) and the Union Pacific Railroad (UP) through the Surface Transportation Board's (STB) Stand Alone Cost Railroad process. This case was filed in December 2008 with opening evidence and argument submitted by AEPCO January 25, 2010. The railroad's reply case is due in May 2010.

AEPCO is also involved in litigation with the UP. UP filed a complaint in January 2009 in U.S. District Court against AEPCO. This complaint alleges that AEPCO refuses to recognize a contract for coal transportation from Colorado and Wyoming coal sources. AEPCO contends that no contract was signed and does not exist. This case continues pending settlement discussions.

AEPCO is not involved in any dispute or litigation with the coal suppliers.

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STF 2-20 To date, has AEPCO engaged in any settlement discussions with the coal suppliers and/or railroad concerning the matters being litigated? If not, explain fully why not. If so, please briefly summarize the status of such discussions.

Respondent: Dwight M. Whitley Jr., Corporate Counsel

Response: AEPCO has been involved in settlement discussions with both the Union Pacific Railroad (UP) and the BNSF Railway (BNSF). AEPCO is currently engaged in settlement discussions with the UP. While settlement proposals were exchanged between AEPCO and the BNSF, these proposals were rejected by both parties and AEPCO and the BNSF are not currently engaged in settlement discussions.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

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-01773A-09-0472

DIRECT

TESTIMONY

OF

RANDALL VICKROY

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 02, 2010

ALL-STATE LEGAL®
EXHIBIT
S-2

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EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-09-0472

AEPCO has requested a slight decrease in its overall revenue requirement of about $97,000 annually, or a decrease of 0.06 percent. AEPCO has based its revenue requirement request on targeting a Debt Service Coverage ("DSC") of 1.275 and a Times Interest Earned Ratio ("TIER") of 1.30, along with a composite cost of debt of 5.92 percent for the test year ended March 31, 2009. AEPCO's actual net margins during the test year were $15.8 million. However, the loss of three major wholesale sales contracts and increases in coal costs and other operating expenses have caused the Cooperative to make $12.5 million in pro forma reductions in margins by December 31, 2010. AEPCO is not proposing to increase its rates to recover these lost margins; the expected net margin level with proposed rates drops to only $3.2 million.

I have determined a target range for DSC on which rates should be set at 1.25 to 1.45. My analysis applies credit rating agency financial targets and credit risk profiles for generation and transmission cooperatives, and applies them to AEPCO. I recommend that AEPCO's DSC should be 1.40, due to the Cooperative's overall credit risk profile which would also produce a TIER of 1.51 and net margins of about $5.5 million annually.

INTRODUCTION

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

A. My name is Randall Vickroy. I am a senior consultant for The Liberty Consulting Group ("Liberty") My Liberty business address is: The Liberty Consulting Group, 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Have you prepared summaries of your background and qualifications?

A. Yes, they are provided in Exhibit LCG-1.

Q. Mr. Vickroy, please describe your educational background and professional experience as they relate to the subjects of this testimony.

A. I spent 12 years with a major Mountain States electric and gas utility, starting as a Financial Analyst in the corporate finance and planning department, and then became Financial Supervisor, Director of Analysis, Business Development Manager, and Assistant to the Chief Financial Officer. My responsibilities included financial planning, capital acquisition, capital spending analysis and allocation, treasury operations, securitization financing, project financing, mergers and acquisitions, cash management, and investor relations.

I have been consulting since 1991 on corporate finance and business issues in the electricity, natural gas, and telecommunications industries. During this time, I have provided consulting services to utility commissions and to companies in over 25 states and in three foreign countries. I received a Bachelor of Arts from Monmouth College with a major in business administration and a Masters of Business Administration degree from the University of Denver with an emphasis in finance.

Q. For whom are you appearing in this proceeding?

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

Q. What is the purpose of your testimony?

A. My testimony provides a review, evaluation, and recommendations regarding the cost-of-capital issues for the Arizona Electric Power Cooperative ("AEPCO" or "Cooperative") rate filing, as summarized in its Amended and Restated Schedules A-1 and A-2. Cost-of-capital issues include the cost of debt, risk factors as they affect the cost of capital, financial coverage ratios such as Times Interest Earned Ratio ("TIER") and Debt Service Coverage ("DSC"), equity ratios, and cash flow metrics and indicators. I also discuss my evaluation of whether AEPCO's cost-of-capital request provides adequate margins, debt coverage, and cash flow to finance its investment and operations as of the test year ended March 31, 2009.

Q. Why does AEPCO consider the rate increase request to be necessary?

A. AEPCO has experienced strong financial performance in each of the years 2007 through 2009. The higher net margins generated during recent years have increased AEPCO's equity ratio as a percentage of capitalization, from only about 5 percent at the end of 2005 to over 28 percent at March 31, 2009. However, by December 31, 2010 a series of very significant business changes will substantially affect AEPCO's financial outlook. The largest items affecting financial status are increases in coal prices and the expiration of three large sales contracts to AEPCO's Class B members. The contract loss of most significance is the expiration of the 100 MW Salt River Project ("SRP") contract on December 31, 2010. This contract produces $13.2 million of annual margins. Part of the margins from these lost contract sales will be offset by assigning portions of the contract

capacity to Mohave Electric Cooperative ("Mohave") and Sulphur Springs Valley Electric Cooperative ("Sulphur Springs"). AEPCO has also experienced higher overhaul and maintenance costs on its power plants in recent years, as the plants age. AEPCO has presented a series of pro forma adjustments for these major changes, which have a net result of decreasing margins by $12.5 million annually, as shown in AEPCO's Amended and Restated Schedule C-2, page 10 of 10.

AEPCO's request does not include a rate increase to offset the lost margins. AEPCO had a net margin of $15.8 million in the test year ended March 31, 2009. Under the proposed rates, the net margin is expected to fall to $3.2 million.

AEPCO FINANCIAL RESULTS

Q. What have APECO's financial results been over the past several years?

A. The DSC, TIER, and equity as a percent of total capitalization comprise primary financial ratios and indicators of AEPCO's financial health under AEPCO's Rural Utilities Service ("RUS") mortgage and other existing loan documents. AEPCO's RUS mortgage agreement debt covenants require both a DSC and a TIER of at least 1.0 in two of three consecutive years. Exhibit LCG-2 provides AEPCO's DSC, TIER, and equity ratio for each year from 2000 through 2009.

We consider the DSC to be more significant and important here than the TIER. The DSC takes into account components of cash flow (such as depreciation and principal payments), and provides a better indicator of an enterprise's generation of sufficient cash to meet its debt and principal requirements. TIER is more focused on book earnings, rather than cash. Exhibit LCG-2 shows that AEPCO's DSC ratios were below its mortgage document requirements in each year from 2003 through 2005. Following a rate increase, AEPCO's

DSC improved to 1.16, 1.37, 1.33 and 1.70 for the years 2006-2009, respectively. TIER levels were 2.13, 2.81, 2.66 and 1.94 for the same years. AEPCO's equity ratio increased from about 5 percent at the end of 2005 to 29.45 percent at the end of 2009. AEPCO's financial results and covenant coverage ratios have been strong since the 2005 rate case and through the test year.

Q. Please summarize AEPCO's actual results for the test year, and as affected by the loss of the SRP contract business, coal price increases, and the other factors it has cited.

A. AEPCO's Amended and Restated Schedule A-2 reports actual net margins of about $15.8 million for the test year ended March 31, 2009. AEPCO's adjustments for margins lost from its power sales contracts, increased coal costs, and other adjustments to operating expenses reduce that healthy margin to $3.3 million for the same test year. AEPCO's DSC for the test year would fall from 1.39 to 1.28, and TIER would fall from 2.50 to 1.30.

Q. What would AEPCO's expected financial results for the test year be if its proposed rate adjustment is approved?

A. AEPCO based its requested rate change upon producing the revenue necessary to achieve a DSC of 1.275 in the test year. The requested slight rate decrease would also result in a TIER of about 1.30. AEPCO has calculated that these coverage ratios would provide net margins of about $3.2 million per year. AEPCO has estimated that the slight reduction in rates would decrease equity as a percentage of capitalization to 27.5 percent from about 28.1 percent at the end of the projected year ending March 31, 2010.

AEPCO COST OF DEBT

Q. Please summarize AEPCO's calculations of its cost of debt.

A. AEPCO's Amended and Restated Schedules D-1 and D-2 calculate long-term debt interest for the test year ended March 31, 2009 as $10,812,194, on debt outstanding of $178.1 million. The long-term debt interest arises primarily from interest on AEPCO's Federal Financing Bank ("FFB") debt. This debt consists of numerous notes, which account for about $111.7 million (over 62 percent) of long-term debt outstanding. AEPCO also had outstanding at March 31, 2009 long-term debt with the following lenders: Central Bank for Cooperatives ($21.1 million), the National Rural Utilities Cooperative Finance Corporation ("CFC") ($29.5 million), CFC Series 1994A bonds ($15.4 million), and Rural Electric Administration ("REA") debt of $0.5 million.

AEPCO annualized the interest charges for long-term debt in place at the end of the test year. AEPCO then added to the annualized interest expense a $0.329 million payment to SWTC for interest on regulatory assets that remained on AEPCO's books following the 2001 restructuring. The net result of annualizing the interest and adding the SWTC interest payments was a net increase of $231,437 above the test year's actual long-term debt interest costs. AEPCO's Schedule D-2 for the test year shows the results of the annualization of interest charges. Annualized long-term debt interest of $10.812 million produces a cost rate of 6.07 percent on the $178.1 million principal for the test year.

AEPCO's cost of capital filing also includes short-term debt of $15.85 million outstanding on its $25 million CFC credit facility at March 31, 2009. The interest rate is 4.25 percent. AEPCO Schedule D-1 shows a cost of debt summary for AEPCO, generating a composite rate of 5.92 percent on $193.9 million of total debt outstanding.

Q. What do you conclude about the appropriateness of AEPCO's annualization adjustment as a basis for adjusting the cost of debt?

A. I consider the interest annualization to be properly reflective of a known and measurable adjustment process. The annualization updates the cost of debt for new issuances and for maturities of existing debt that occur during the test year. It better represents debt costs expected to be incurred, when compared with test-period interest expense.

Q. Does AEPCO expect its long-term debt to change significantly following the test year?

A. Yes. To reflect expected additional draws from FFB and maturities on some of its other debt outstanding, AEPCO also projected in Schedules D-1 and D-2 that its long-term debt would increase from $178.1 million to $192.8 million in the 12 months following the test year. For instance, AEPCO had drawn $26.2 million of FFB debt in 2009, and expected to draw an additional $12 million prior to March 31, 2010. Each draw would be at interest rates lower than the 6.07 percent of the test year. The weighted average cost of the long-term debt would decrease from the annualized 6.07 percent to 5.72 percent. However, AEPCO's estimates of the out-of-test-period changes in the principal amount outstanding and the weighted average cost of long-term debt are not known and measurable adjustments that AEPCO has requested.

Q. Please describe your understanding of the extension of maturities on AEPCO's FFB debt and its effect on debt principal payments.

A. AEPCO (as well as SWTC) recognized that very high levels of principal payments on its long-term debt greatly exceeded the depreciation levels built into existing rates. This phenomenon caused cash flow shortages even as net margins remained healthy during the past few years. For instance, principal payments for AEPCO in 2007 were $17.8 million,

while depreciation and amortization amounted only to $8.0 million. The elevated principal payment levels also made meeting minimum DSC ratios more difficult, because principal payments are included in DSC obligations that must be "covered" with operating cash sources. AEPCO and SWTC discussed with RUS extending the loan maturities on certain FFB issuances to coordinate their terms better with the cooperatives' new, longer estimates of the remaining generation and transmission asset useful lives. As of December 31, 2008, the maturities of most AEPCO loans with FFB had been extended.

The maturity extensions greatly reduced principal payments, starting in 2009. Total principal payments for AEPCO were $14.1 million during the test year, but were projected to fall to $6.8 million in the following 12 months. As a result of extending the maturities, AEPCO will have higher DSC coverage and cash flow following the test year.

Q. Please explain AEPCO's request for the inclusion of short-term debt in the capital structure as of March 31, 2009.

A. AEPCO had, at the end of the test year on March 31, 2009, $15.85 million outstanding on its $25 million credit facility with CFC. AEPCO included this short-term debt amount in its cost of debt calculation, at an interest rate of 4.25 percent. AEPCO has effectively annualized the interest rate on the $15.85 million amount, and included it in the cost of debt, consistent with the long-term debt portion. AEPCO's rationale in including short-term interest in the cost of capital is the assumption that a similar level of short-term debt is required to fund the various working capital needs of AEPCO during the test year. This rationale is reasonable for the cost of debt calculation and its inclusion results in a lower composite cost of debt.

Q. What is your overall evaluation of the AEPCO's requested cost of debt as presented in Schedules D-1 and D-2?

A. AEPCO's requested composite cost of debt of 5.92 percent accurately represents the annualized cost of debt experienced by AEPCO as of the end of the test year on March 31, 2009.

AEPCO RETURN REQUIREMENTS

Q. Please explain your method for estimating AEPCO's cost of capital and coverage requirements.

A. I have evaluated AEPCO's cost of capital and coverage requirements based on risk evaluation techniques used by the credit rating agencies. The rating agency techniques include both quantitative criteria that are based on financial metrics and qualitative criteria associated with the business risks of generation and transmission ("G&T") cooperatives. The financial credit metrics provide a quantitative foundation for the financial results required to achieve a lower-to-mid-level investment grade rating. I then factored in qualitative criteria also used by the rating agencies to evaluate the business risks that are specific to AEPCO. Utilizing both the quantitative and qualitative risk factors, I then established a target range of DSC coverage ratios that may be used to set rate levels. As I have noted previously, the DSC ratio is preferred for use in evaluating G&Ts financial strength, because it takes into consideration cash requirements and principal payments, which are substantial for most cooperatives.

The actual historical levels of financial results for G&T cooperatives may then be checked against the target range to test for reasonableness. Finally, I considered AEPCO's current prospects (as indicated by its projected capital expenditure program, cash situation, and

other contingencies), in order to determine the recommended DSC level, and its commensurate cash flow, within the established range.

Q. How do you define the required rate of return or cost of capital used to set rates for AEPCO?

A. The determination of a coverage ratio to calculate AEPCO's return requirements must produce financial results that will allow AEPCO to meet member power requirements, maintain financial strength, and raise capital from the RUS and CFC and from capital markets, as necessary. A fundamental principle of utility finance, whether the utility is investor-owned or a cooperative, is that the enterprise must be able to attract capital at a reasonable cost in order to build and maintain its physical plant and to meet its public service obligations. The failure to maintain the financial integrity of a cooperative is not in the interests of either its members or lenders. At a minimum, an entity like AEPCO must be afforded the opportunity not only of assuring its financial integrity to attract additional capital as needed, but also of achieving margins and financial results that are commensurate with its risk profile.

Q. Please explain your basis for determining the appropriate risk parameters for AEPCO.

A. The established sources of evaluations of risk and credit standing are the three major credit rating agencies: Moody's Investors Service ("Moody's"), Standard and Poor's ("S&P"), and Fitch. The rating agencies apply similar criteria when evaluating the risks of G&T cooperatives. Moody's has recently updated and refined its criteria for rating G&Ts, and has clearly defined its actual ratings on 17 electric G&T cooperatives as of December 2009. However, these rating agency criteria are appropriate for determining a

reasonable target for financial metrics that fully considers the business and financial risks of AEPCO.

Q. What are the primary factors that rating agencies consider important in assessing the risk of G&T cooperatives?

A. The rating agencies' analysis of U.S. electric G&T co-ops focuses on five key rating factors considered central to assigning ratings in this sector. These rating factors include quantitative and qualitative measures for establishing the risk profile of a cooperative. The five key factors and Moody's weighting of each factor are as follows:

1. Financial Performance and Metrics (40 percent)
2. Long-term Wholesale Power Supply Contracts/Regulatory Status (20 percent)
3. Rate Flexibility (20 percent)
4. Member Profile (10 percent)
5. Size (10 percent).

Financial performance and strength are important indicators of a G&T cooperative's ability to meet its obligations, especially interest and debt service. The rating agencies analyze financial indicators and ratios to measure the ability to cover fixed and variable obligations. They analyze the DSC and the TIER, recognizing that these two ratios have been used to measure minimum compliance with RUS loan documentation for many years, and provide a bare, minimum level of financial results that must be met. They also analyze standard cash flow indicator ratios, specifically funds from operations coverage of interest ("FFO/Interest") and funds from operations coverage of debt ("FFO/Debt"). These ratios are most important to the rating agencies, because they provide insight into the amount and quality of a cooperative's cash flow and its ability to service its debt. Cooperative equity as a percentage of total capitalization is also evaluated by the rating

agencies to determine how much flexibility exists on the balance sheet to absorb unexpected events and losses.

These five financial ratios comprise the primary quantitative determinants of the risk profile for G&T cooperatives. Together, they account for 40 percent or more of the weighting in rating agency evaluations.

The remaining four criteria categories used to develop risk profiles are more qualitative in nature, but most are measurable. Long-term wholesale power supply contracts between G&T cooperatives and their members provide G&Ts with a high degree of assurance that costs and capital investment can be recovered in rates charged to members. Most of these member wholesale contracts require the member cooperatives to purchase all or virtually all of their power supply from the G&T. The members must also pay their pro-rata portion of the G&T's fixed and variable costs. A higher percentage of capacity and energy sold to full or partial requirements members is considered less risky than outside wholesale contracts or other sales to non-members. Regulatory status is also part of this ratings factor. Regulatory control over the rate setting process (such as in Arizona) is considered by the rating agencies to leave a cooperative with less flexibility to raise rates if needed.

Rate flexibility is another credit factor that relates to cost recovery efficiency. The timing and extent to which a G&T cooperative can increase rates is influenced by how active its board of directors has historically been regarding rate actions. Fuel and purchased-power adjustment mechanisms are viewed favorably, especially when the recovery of cost increases is deferred for shorter time periods. The degree of reliance on purchased power comprises another credit factor. Heavy reliance indicates higher exposure to price

volatility. New-build exposure is also measured by the rating agencies. A larger construction program is considered to be a credit negative, because the issuance of increased levels of debt to finance the program and resulting rate increases increase risk. Finally, cost competitive cooperatives are viewed more favorably, because they have greater flexibility to raise rates as costs rise or to build equity capital to levels that would cover operational problems.

Member profiles measure the degree of a G&T's residential sales, or less risky sales, by its members. The consolidated member's equity capital as a percentage of capitalization is also considered in determining the strength of members.

The size factor is measured by megawatt-hour sales and by net property, plant, and equipment. The rating agencies believe that megawatt-hour sales comprise an important indicator of economies of scale. They also believe that having a greater asset base may be beneficial if the G&T can benefit from having a larger pool of assets and a more diverse source of fuels to operate the generation assets that it owns. Less asset concentration in one generating plant is considered preferable due to the risk of extended outages and replacement power costs.

Q. Please explain how you analyzed the rating agency targets for financial metrics to apply to AEPCO.

A. I used Moody's financial metrics for electric G&T cooperatives to determine the financial criteria for both a "Baa" rating and an "A" rating. Moody's has published a range for each rating level for each of the five key financial metrics for G&Ts mentioned previously. I consider the Baa rating, the lowest investment grade category, to be the minimum acceptable rating and level of financial strength here. I have also included the "A" rating

criteria so that financial metric mid-points related to the combination of the A and Baa categories may be determined. My Exhibit LCG-3 provides the ranges of financial metrics that qualify for each of the Moody's ratings levels. Exhibit LCG-3 also shows the mid-point of these two ratings ranges for each financial metric, which I consider to be a reasonable target for the quantitative financial metric portion of this analysis. Exhibit LCG-3 also provides the pro forma financial metrics that would be generated by AEPCO during the test year under its proposed rates, as shown in AEPCO's Schedule A-2.

Please note in the exhibit that values for the mid-points of the ratings categories for the financial metrics are generally close to the pro forma results of AEPCO's rate request. The rating mid-point DSC coverage, for instance, is 1.25, as compared to the company's request of 1.275. Based solely upon the quantitative metrics, AEPCO's rate request could produce financial results that would qualify the Cooperative for an investment-grade credit rating in either the Baa or A categories. However, we have yet to account for numerous qualitative factors and AEPCO business factors that can influence these quantitative results upward or downward.

Q. How do qualitative factors influence the analysis of AEPCO's risk profile?

A. The financial metrics provide a quantitative basis for determining AEPCO's risk profile. We have determined that the financial targets included in its rate request, if realized over a period of years, would probably qualify the company to be rated around A-/Baa+. As we have noted, Moody's gives a 40 percent weight to the financial metrics and 60 percent to the remaining four rating factors. I should also note here that the other ratings factors to be discussed often tend to have an overriding influence on whether an enterprise can actually realize the targeted returns included in rate filings.

AEPCO is somewhat more risky with regard to the rating factors of long-term wholesale power supply contracts and regulatory status. The Cooperative has a high percentage of member load under long-term partial requirements contracts through 2035, which is a positive rating factor. On the other hand, AEPCO is rate-regulated by the ACC, which Moody's considers a negative factor for purposes of ratings. The combination of AEPCO's member wholesale contract status and regulatory status falls into Moody's "Baa" category, a somewhat negative rating factor as compared to its targeted financial metrics.

The rate-flexibility factor indicates overall higher levels of risk for AEPCO. Two out of the four rate-flexibility categories would be placed in Moody's "Baa" category. These two are board involvement in setting rates/fuel recovery mechanisms and new-construction-build exposure. In the rate competitiveness category, AEPCO would be significantly riskier, falling between the "Baa" and "Ba" (below investment grade) categories. The Cooperative's low purchased power percentage is a positive ratings factor.

The member/owner profile factors include percentage of residential sales, which is a positive factor for AEPCO. The equity capitalization of members would fall in the Baa category, or a relatively negative factor. The size rating factor is a strongly negative factor for AEPCO, both with regard to megawatt-hour sales and net property plant and equipment. These two rating factors are below investment grade for AEPCO, and have to be considered a negative rating factor for AEPCO.[1]

[1] Size is a qualitative factor used by Moody's to establish a credit risk profile which is different from using size as a unique risk factor in cost of equity estimation. The Commission denied a proposal to assign a size risk premium in Decision No. 64282 and found that a firm size phenomenon does not exist for regulated utilities in Decision No. 64727.

The nonfinancial rating factors evaluated here indicate that AEPCO carries significant levels of added risk due to its regulatory status, rate flexibility criteria, and small sales and asset bases. I believe that these factors indicate that AEPCO carries business risk in these areas at levels material enough to consider in the determination of a target DSC range.

Q. What do you consider to be an appropriate range for Debt Service Coverage for AEPCO to target?

A. I believe that an appropriate target range for AEPCO's DSC is 1.25 to 1.45. I would consider the lower bound of the range to be set by the theoretical realization of financial results consistent with a 1.25 DSC, which would translate into a lower investment grade credit rating. On the other hand, the non-financial criteria discussed above indicate that AEPCO carries characteristics of a credit risk profile that call for a higher targeted DSC of up to 1.45. I believe that a reasonable targeted DSC within this range should maintain the financial health of AEPCO.

Q. How does this recommended range compare to the actual financial metric results of G&Ts in recent years?

A. The CFC prepares operating and financial statistics for G&T cooperatives on an annual basis, presenting them in the Key Trend Ratio Analysis ("KTRA"). The KTRA provides data for G&Ts overall, as well as for four sub-categories of G&T businesses. One of the sub-categories is generation companies that generate more than one-half of their power requirements. This category describes AEPCO well. The financial metrics of DSC, TIER, and equity ratio are comparable among all cooperative generation companies.

Exhibit LCG-4 provides these three ratios for the KTRA generation group and all G&Ts for the years 2005 to 2008. Overall TIER and DSC levels improved significantly from

2005 to 2008. The realized DSC levels of both the cooperative generation comparison group and all G&Ts each increased to 1.34 in 2008 from previously lower levels. Exhibit LCG-4 compares recent DSC levels realized by cooperative generation companies and G&Ts with my target DSC range. The most recent realized DSC levels of 1.34 in 2008 fall squarely in the middle of my recommended target DSC range of 1.25 to 1.45. The KTRA information indicates that this recommended target range is reasonable and at the levels actually experienced by cooperative generation and G&T cooperatives.

RATE SUFFICIENCY

Q. Does AEPCO's request for a target DSC of 1.275 provide supporting information indicating that AEPCO will have a sufficient return and cash flow?

A. No. AEPCO has calculated its net margin with its proposed rates at only $3.2 million, which I believe is too thin from both a net margin and cash flow perspective. This thin level of operating and net margins provides little earnings cushion to cover unexpected operating problems and contingencies. It also does not provide sufficient cash generated by AEPCO's operations to meet its cash obligations. AEPCO's Schedules A-5 and E-3 show that, with the proposed rates in effect, net cash provided by operating activities would be only $3.6 million for the test year, as compared to net cash requirements of $21.2 million. The net annual cash shortfall would thus be about $17.6 million. The rate filing indicates that cash flow would not be adequate even if requested rates were approved.

I do not believe, however, that the cash situation is quite so dire on a going-forward basis. I have requested forecasted financial information from AEPCO to determine if AEPCO will have sufficient cash generation to meet its cash obligations in future years. These years include a greatly increased capital budget when compared with recent years.

Unfortunately, AEPCO has not been able to provide a recently-prepared financial forecast that I could review prior to preparing this testimony.

AEPCO has stated in its testimony that it has already experienced severe cash flow problems during the past few years, even while margins were strong. These cash shortages arose from temporary under-collections for fuel caused by volatile fuel prices, the high level of principal payments prior to extending debt maturities with the RUS, and the financing of increasing dollar levels of coal inventory. These inventory costs rose due to coal price increases and inventories that greatly exceeded target levels. The information that AEPCO provided led me to conclude that both the net margin and resulting cash flow proposed by AEPCO will not be sufficient to meet future needs.

Q. What potential problems may occur by targeting a "minimum level" DSC; i.e., one at the lower end of your range?

A. AEPCO's financial results could deteriorate quickly during the next few years, potentially wiping out its small requested net margin and causing additional cash requirements. Following the end of the test year, AEPCO plans capital expenditures of about $85 million during the following 36 months. The unrecovered financing costs of these capital expenditures would reduce earnings by about $500,000 in the first 12 months, $1.9 million in the second 12 months, and $3.5 million in the third 12 months. With its historical test year, AEPCO is also susceptible to any operating expense increases that may occur. For instance, a major plant outage and the replacement power costs required could also easily eliminate the net margin included in its rate request. AEPCO will also have to pay for mercury control chemicals that are not included in this rate filing. AEPCO estimates those at $600 thousand to $2 million annually. I expect that AEPCO will face great difficulty in earning the $3.2 million in annual net margins that it proposes.

Q. What are your target DSC, TIER, and net margin recommendations for AEPCO?

A. Based on the higher credit risk profile that I have identified for AEPCO, I recommend that rates be set based upon a DSC that is near the upper end of my recommended DSC range of 1.25 to 1.45. I recommend that a target DSC of 1.40 be adopted for rate setting purposes. This DSC level would produce net margins of about $5.5 million annually and a TIER ratio of 1.51.

Q. Does this conclude your Direct Testimony?

A. Yes.

Randall E. Vickroy

Areas of Specialization

Mr. Vickroy has over 25 years of experience in the utility industry, including fifteen years as a management consultant. He has managed and performed numerous high-level consulting assignments at companies and utility commissions in over 25 states. His areas of expertise include corporate finance and treasury management; capital markets and financing vehicles; utility industry restructuring; utility rates and pricing; non-regulated lines of business and affiliations; strategy and planning issues; asset valuations and decision-making; capital and expense budgeting and forecasting; corporate resource allocation; and financial and economic analysis.

Relevant Experience

Lead Consultant on electrical energy and capacity purchases and sales and hedging and capital budgeting on Liberty's management and operations audit of the electricity, natural gas, and steam operations of ConEd for the New York Public Service Commission.

Served as Lead Consultant in an audit of the fuel and purchased-power procurement practices and costs of Arizona Public Service Company for the Arizona Corporation Commission. Responsible for reviews of its contracting and supply-management practices for natural gas. His assignment in the Arizona project included an examination of the reasons for differences in off-system sales between Arizona Public Service, including specifically PNM and Salt River Project

Led the review of finance and the protection and insulation of the utility from parent and non-utility operations and finances on Liberty's focused and general management audits of NJR, New Jersey Natural Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues.

Lead Consultant in Liberty's audit of Duke Energy Carolinas for the North Carolina Utilities Commission, focusing on issues of compliance with regulatory conditions and code of conduct.

Led the review of finance and the protection and insulation of the utility from parent and non-utility operations and finances on Liberty's focused and general management audits of SJI, South Jersey Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues.

Lead for examination of financing and risk management on Liberty's focused audit of NUI Corporation and NUI Utilities. This audit included a detailed examination of the reasons for poor financial performance of non-utility operations, affect of affiliate operations, including commodity trading on utility credit and finance, downgrades of utility credit beneath investment grade, and retail and wholesale gas supply and trading operations. The audit included detailed examinations of financial results, sources and uses of funds, accounting systems and controls, credit intertwining, cash commingling, and affiliate transactions, among others. Liberty's examination included very detailed, transaction-level analyses of commodities trading undertaken by a utility affiliate both for its own account and for that of utility operations.

Served as Lead Consultant in Liberty's review of acquisitions of UniSource (Arizona) and Portland General Electric (Oregon) focusing on utility financial insulation, governance, service reliability, access to information, and community presence issues.

Lead Consultant in Liberty's comprehensive analysis of the ratemaking implications of Commonwealth Edison's Chicago electric service outages for the Illinois Commerce Commission. Responsible for investigating and analyzing ComEd's capital budgeting, resource allocation, project management, expenditure levels and rate base impacts for operations leading up to and in response to the outages.

Lead Consultant in Liberty's review of the financial integrity and earnings of Verizon New Jersey's rate regulated and competitive businesses for the New Jersey BPU. Responsible for the financial evaluation of VNJ's earnings, capital structure, rates of return, dividend policies, credit ratings, financial reporting, SEC reporting, and BPU surveillance reports.

Lead Consultant in Liberty's financial audit for ratemaking purposes of Verizon New Hampshire for the New Hampshire Public Utilities Commission. Responsible for a broad and comprehensive analysis of the financial status of VNH, including an audit of the books and records of the Verizon parent, in order to assist the commission in determining rate base, rates of return and appropriate adjustments for the test year.

Project Manager for the development and implementation of regulatory financial systems and models for deregulated ratemaking at Pacific Gas and Electric Company. The project involved developing regulatory strategy, California PSC earnings monitoring models, data bases, analytical models and reporting for all regulatory requirements of PG&E's regulated businesses.

Led the development of a framework and strategy to resolve all electric industry restructuring issues between the State of New Hampshire, Public Service Company of New Hampshire, and the NHPSC. Project included assessment and valuation of all key assets and development of a disposition strategy for all generation assets, contracts and obligations. The project also included the assessment of alternative rate paths; planning for the securitization and recovery of stranded costs; and the development of provisions for power supply purchases during a transition period.

Team leader for the review of the New York Power Authority's profitability, financial reporting, rate competitiveness, pricing policies, power plant economics and economic development

programs in this management audit for the state of New York. NYPA is the largest generator and carrier of power in New York, providing over 25 percent of the electricity sold.

Team leader in providing consulting assistance to Kentucky Utilities in preparing its 1993 application for implementing an environmental surcharge. Responsibilities included analyzing legislation, analysis of capital expenditures, analysis of KU's Clean Air Act compliance plan, analysis of costs recoverable under the surcharge, and developing testimony, exhibits, special accounting systems, and rate tariffs.

Project Leader for providing consulting assistance to Big Rivers Electric in preparing its 1994 application for implementing an environmental surcharge. Responsibilities included a review and evaluation of the economics of a major investment in a flue gas scrubber, analysis of Big Rivers' Clean Air Act compliance plan, evaluating cost recoverable under the surcharge, and developing surcharge testimony, exhibits, accounting systems and rate tariffs.

Consultant in Liberty's management audit of GTE South - Kentucky for the Kentucky Public Service Commission. Responsible for the analysis of the financial-management of GTE as it relates to the operation of its GTE South subsidiary.

Lead Consultant in Liberty's management audit of Bell Atlantic - Pennsylvania and Bell Atlantic - District of Columbia for their respective commissions. Responsible for reviewing Bell Atlantic's capital structure, finance and controller functions, financial systems, and treasury operations. Focus areas included the impact of telephone industry competition on capital budgeting, financial management strategy, and treasury operations.

Leader for all financial areas in the review of affiliate transactions among Public Service Electric and Gas, its holding company parent, and the extensive diversified businesses of the holding company. Responsible for evaluating PSE&G's consolidated finance functions to determine whether the financial integrity, flexibility, and cost of capital of the regulated utility had been adversely affected by the activities of diversified affiliates. Work included the review and analysis of the long-term financing, cash management, direct and indirect credit support mechanisms, investor relations, and all transactions between and among the affiliates.

Led the review of finance, cash management, budgeting, and rates in Liberty's comprehensive management audit of Southern Connecticut Gas for the Connecticut DPUC. Responsibilities included operational audits of all finance, regulatory and budgeting processes of SCG.

Led the review of the finance, cash management, budgeting, accounting and rate functions in Liberty's comprehensive management audit of Connecticut Natural Gas for the Connecticut DPUC. Work also included a focus on the financial impacts of CNG's non-regulated businesses, which includes a large steam system in downtown Hartford.

Led the review of the finance, cash management, budgeting, rates, and tax functions in Liberty's comprehensive management audit of Yankee Gas for the Connecticut DPUC. Evaluation

included an in-depth analysis of the effectiveness of Yankee's capital and expense budgeting processes and the integration of market and competitive components into these processes.

Led the review of the finance, regulatory and accounting functions in Liberty's management audit of United Cities Gas for the Tennessee Public Service Commission. Responsibilities included a review of all financial functional areas, as well as a review of the impact of all affiliate transactions between the regulated and non-regulated businesses.

Led the evaluation of the financial relationships between Hawaiian Electric Industries and Hawaiian Electric Company for the Hawaii Department of Commerce and Consumer Affairs. The focus of the review was the credit and financial support provided by the utility company to the holding company and its diversified businesses.

Led the review and analysis of corporate governance, financial relationships and affiliate transactions between Virginia Power and its parent, Dominion Resources for the Virginia State Corporation Commission. The review included an evaluation of all utility and non-utility financing, governance and economic impacts. The engagement was in response to a well-publicized dispute between the holding company and Virginia Power.

Led the consulting and monitoring of contracting for electric supply by Western Massachusetts Power following the sale of its generation assets under electric deregulation.

Led the review and evaluation of the financial management practices of a major utility holding company. Engagement included an assessment of overall financial management and crisis-liquidity plans; strategic and business planning; asset valuations and their accounting impacts upon deregulation; independent power contract buy-downs; and rate reduction strategies.

Led the evaluation and recommendation of strategic lines of business for a major municipal utility facing industry deregulation.

Led the development of a strategic framework for the establishment and growth of non-regulated businesses for a major international electric holding company.

Led the development, analysis, and recommendation of alternative electric generation and power resource strategies for a regional generation and transmission company in preparation for electric deregulation.

Led the review and evaluation of all utility and non-utility financing, financial relationships, and affiliate transactions between a major utility holding company and its electric company subsidiary.

Leader for all financial areas in the evaluation of the diversified businesses of a major utility holding company. Engagement determined the impact on financial integrity, financial flexibility, credit mechanisms, and the cost of capital of the substantially diversified businesses of the holding company.

Led the development of an overall gas business strategy, capital asset allocation methods, financial analysis programs and gas main extension policy for a Midwestern combination utility.

Education

M.B.A., Finance, University of Denver

B.A., Business Administration, Monmouth College

Arizona Electric Power Cooperative, Inc.
Computation of TIER, DSCR and Equity Ratios
Twelve Months Ended December 31, 2000 through 2009
Response to STF 4.112

Description	12 Mos. Ended 12/31/00	12 Mos. Ended 12/31/01	12 Mos. Ended 12/31/02	12 Mos. Ended 12/31/03	12 Mos. Ended 12/31/04	12 Mos. Ended 12/31/05	12 Mos. Ended 12/31/06	12 Mos. Ended 12/31/2007 (1)	12 Mos. Ended 12/31/08	12 Mos. Ended 12/31/09
Times Interest Earned Ratio Calculation:										
Net Patronage Capital or Margins	$ 12,070,720	$ 10,431,220	$ 3,898,571	$ (7,848,847)	$ 293,222	$ 426,624	$ 13,980,512	$ 20,549,535	$ 17,355,771	$ 9,956,925
Interest on Long-Term Debt	18,251,166	16,050,770	12,825,566	12,200,997	12,562,525	12,877,640	12,401,645	11,347,878	10,459,715	10,622,133
Total	$ 30,321,886	$ 26,481,990	$ 16,724,137	$ 5,152,150	$ 12,855,747	$ 13,304,264	$ 26,382,157	$ 31,897,413	$ 27,815,486	$ 20,579,058
Times Interest Earned Ratio	1.66	1.65	1.30	0.42	1.02	1.03	2.13	2.81	2.66	1.94
Debt Service Coverage Ratio Calculation:										
Net Patronage Capital or Margins	$ 12,070,720	$ 10,431,220	$ 3,898,571	$ (7,848,847)	$ 293,222	$ 426,624	$ 13,980,512	$ 20,549,535	$ 17,355,771	$ 9,956,925
Depreciation & Amortization Expense	11,223,824	11,519,596	7,808,510	8,774,081	8,911,221	8,432,257	7,466,357	7,985,116	8,069,925	8,818,475
Interest on Long-Term Debt	18,251,166	16,050,770	12,825,566	12,200,997	12,562,525	12,877,640	12,401,645	11,347,878	10,459,715	10,622,133
Total	$ 41,545,710	$ 38,001,586	$ 24,532,647	$ 13,926,231	$ 21,766,968	$ 21,736,521	$ 33,848,514	$ 39,882,529	$ 35,885,411	$ 29,397,533
Principal Payments	$ 15,613,967	$ 13,769,035	$ 11,830,358	$ 12,551,536	$ 13,541,855	$ 14,989,167	$ 16,815,465	$ 17,801,025	$ 16,478,234	$ 6,673,550
Interest on Long-Term Debt	18,251,166	16,050,770	12,825,566	12,200,997	12,562,525	12,877,640	12,401,645	11,347,878	10,459,715	10,622,133
Total	$ 33,865,133	$ 29,819,805	$ 24,655,924	$ 24,753,532	$ 26,104,380	$ 27,866,807	$ 29,217,110	$ 29,148,903	$ 26,937,949	$ 17,295,683
Debt Service Coverage Ratio	1.23	1.27	1.00	0.56	0.83	0.78	1.16	1.37	1.33	1.70
Equity as a Percent of Total Capitalization:										
Margins and Equity	$ 7,971,346	$ 13,904,998	$ 17,803,568	$ 10,754,721	$ 11,047,943	$ 11,474,569	$ 25,455,081	$ 57,280,298	$ 74,558,070	$ 84,514,994
Short Term Debt	5,058,217	4,584,386	4,978,804	1,834,800	3,948,668	15,246,584	22,873,845	24,699,949	17,534,537	22,442,810
Long Term Debt	302,891,350	202,660,477	210,418,005	212,811,754	214,299,718	205,357,382	189,137,907	148,844,055	172,518,677	180,049,657
Total Capitalization	$ 315,920,913	$ 221,149,861	$ 233,200,377	$ 225,400,475	$ 229,296,329	$ 232,078,535	$ 237,466,833	$ 230,746,302	$ 264,611,284	$ 287,006,661
Equity Ratio Percentage	2.52%	6.29%	7.63%	4.77%	4.82%	4.94%	10.72%	24.79%	28.18%	29.45%

(1) Margins and Equity as of December 31, 2007 reflect an $11.7 million adjustment for change in accounting for overhaul costs. See the audited financial statements for 2007 for more information.

Credit Rating Financial Metrics for G&Ts

Exhibit LCG-3

	A Rated Range	*Baa Rated Range*	*Mid-point of A and Baa Ranges*	*AEPCO ProForma with Rate Request*
Funds From Operations/Debt (FFO/Debt)	6% -10%	3% - 6%	6.50%	5.55%
Funds From Operations/Interest (FFO/Interest)	2.0X - 2.5X	1.5X - 2.0X	2.0X	1.97X
Equity/Total Capitalization	20% - 35%	5% - 20%	20%	27.94%
Debt Service Coverage (DSC)	1.2X - 1.4X	1.1X - 1.2X	1.25X	1.275X
Times Interest Earned Ratio (TIER)	1.2X - 1.4X	1.1X - 1.2X	1.25X	1.30X

Columns A and B from response to STF 4.115, "U.S. Electric Generation & Transmission Cooperatives", Moody's Investors Service, December 2009.

Exhibit LC

Comparison of KTRA G&T Cooperative Key Financial Indicators
With Liberty Consulting Cost of Capital Recommendation

	2005	2006	2007	2008	
Debt Service Coverage (DSC)					
Generation Cooperative Group - KTRA	1.01X	1.08X	1.21X	1.34X	
All G&T Cooperatives - KTRA	1.12X	1.05X	1.25X	1.34X	
AEPCO	0.78X	1.16X	1.37X	1.33X	
Liberty Recommended DSC Range for AEPCO (For future application)					1.25X - 1.4
Times Interest Earned Ratio					
Generation Cooperative Group - KTRA	1.29X	1.46X	1.50X	1.57X	
All G&T Cooperatives - KTRA	1.33X	1.46X	1.46X	1.73X	
AEPCO	1.03X	2.13X	2.81X	2.66X	
Liberty Recommended TIER Range for AEPCO (For future application)					1.26X - 1.5

KTRA information from the response to STF 4.116

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

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-01773A-09-0472

DIRECT

TESTIMONY

OF

DENNIS M. KALBARCZYK

(CONSULTANT)

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 16, 2010

ALL-STATE LEGAL®
EXHIBIT
S-3
ADMITTED

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dennis M. Kalbarczyk. My business address is 910 Piketown Road, Harrisburg, Pennsylvania 17112.

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

A. I am the principal of Utility Rate Resources, and maintain a professional relationship with the Liberty Consulting Group, Inc., ("Liberty"). Liberty has been engaged by the Arizona Corporation Commission ("ACC" or "Commission") to assist the Utilities Division ("Staff") in the review of the Arizona Electric Power Cooperative Inc.'s ("AEPCO" or "Cooperative") application for a general rate increase in Docket No. E-01773A-09-0472.

Q. Briefly summarize your education background and professional qualification.

A. I graduated in 1971 with a Bachelor of Science Degree in Accounting from Husson College (now Husson University), in Bangor, Maine. In 1969, I received an Associate of Arts Degree in Accounting from Strayer College (now Strayer University), in Washington D.C. I am the principal in Utility Rate Resources, which was formed in October 1990. I have prepared over fifty rate case filings which have included almost all key aspects of such filings such as revenue requirement, rate of return, cost of service, rate design, and other specialty tariff rate design matters.

I was employed by Drazen-Brubaker & Associates, Inc. from March 1988 to September 1990. I presented testimony and prepared financial statements necessary for applications for Certificates of Public Convenience before the Pennsylvania Public Utility Commission ("PaPUC"). Additionally, I was responsible for the preparation and filing of rate cases, and testified on behalf of utilities under PaPUC regulation. Prior to March 1988, I was employed

by Metropolitan Edison Company ("MEC"), a subsidiary of GPU Energy, formerly General Public Utilities. I spent three years in MEC's Rate Revenue Requirement Department as a Senior Financial Analyst. My responsibilities included the preparation, review, and analysis of financial reports, budgets, and management responsibility for rate and regulatory matters before the PaPUC.

From 1975 through 1985, I was employed by the PaPUC, responsible for performing financial and operations audits and participating in rate proceedings. I testified on revenue requirements matters in nearly all the major electric rate cases during my time at the PaPUC, and performed audits on electric, gas, and water companies for compliance with Commission regulations in the areas of energy cost, coal and gas contracts, and affiliated service contracts. I testified in Energy Cost Rate, Gas Cost Rate, and Coal Compliance proceedings. I actively participated in developing the Commission's first set of regulations on Fuel Procurement Policy and Procedures, Tariffs and Procedures on Energy Cost Rates for electric companies and Gas Cost Rates for gas companies, and designed computerized procedures for electric utilities to report fossil fuel purchases to the PaPUC. From 1972 to 1975 I held progressive degrees of responsibilities with Certified Public Accounting firms performing accounting, auditing and tax preparation duties.

In my work as a private Consultant, I have specialized in the area of utility rate and economic consulting related to the financial aspects of public utility rates and regulation. My work has encompassed rate case filings, certificates of public convenience, expert testimony, and financial applications for funding by the Pennsylvania Infrastructure Investment Authority. I have participated in regulatory and legal proceedings concerning investor-owned and municipal utilities, and testified before governmental agencies and courts, and have represented utilities as well as consumers of utility services. From 2002 to date, I have been

providing senior level consulting services to Liberty, participating in an audit of electricity distribution service costs for inclusion in revenue requirement before the Illinois Commerce Commission, and serving as a team member on focused audits (for the New Jersey Board of Public Utilities) addressing financing, accounting, and affiliate charges of National Utilities Inc. (Elizabethtown Gas), South Jersey Gas, and New Jersey Natural Gas. I have also participated in Liberty examinations of fuel adjustment mechanism costs and rate design issues for staffs of the Arizona Corporation Commission and the Nova Scotia Utility and Review Board.

I have testified in more than 60 rate and regulatory matters on behalf of state regulatory commissions, utilities, municipal authorities, and various consumer groups.

Q. What do you understand to be the nature of this proceeding?

A. On October 1, 2009, AEPCO filed a general rate application with the Commission, requesting an overall revenue increase of approximately $4.023 million. AEPCO's request reflects a 2.41 percent increase over a test-period adjusted rate base of approximately $231.8 million. On April 30, 2010, AEPCO amended and restated its filing. The amended filing would produce an overall revenue <u>decrease</u> of approximately $97,000 (a 0.06 percent decrease from present rates). AEPCO's amended request seeks approval of all new rates by January 2011, including:

Monthly Charges	Mohave Electric Cooperative ("MEC")	Sulphur Springs Valley Electric Cooperative ("SSVEC")	All-Requirements Member ("ARM")
Fixed Charge	$709,721	$628,440	$862,343
O&M Charge	$1,323,724	$1,172,125	$1,229,653
Base Energy Charge/kWh	$0.03216	$0.03230	$0.03236
Other Existing Resources Charge/kWh	$0.06879	$0.06676	$0.06746

AEPCO proposes to base the monthly billing of each individual ARM on the ARM's proportionate share of the above Fixed and O&M charges from the preceding table.

Q. What is the purpose of your testimony?

A. I am addressing, on behalf of the Staff, AEPCO's fully allocated cost of service study and proposed rate design as submitted by AEPCO witness Gary L. Goble.

II. ALLOCATED COST OF SERVICE STUDY AND RATE DESIGN

Q. Provide a brief overview of AEPCO's allocated cost of service study and proposed rate design.?

A. A fundamental criterion for establishing an adequate rate design is that it should reflect the cost of providing service to the customer or appropriate customer class based upon the cost causative factors commensurate with the customer or class service requirements. In order to determine appropriate rates, the total annual cost of providing service or the annual revenue requirement must be allocated among the various customers or customer classes based upon their respective cost causative factors. A detailed fully allocated cost of service study is generally performed to determine the cost of service for the respective customer classes. From a ratemaking perspective, rates based upon the fully allocated costs of service study are deemed to be cost-based.

In certain circumstances it may be appropriate to deviate from this approach; however, care must be taken to minimize the impact on customers, given that basing rates on non-cost of service principles and techniques can create issues of cross subsidization among classes. AEPCO's proposed rate design is cost-based. By way of additional comment, while I reviewed both AEPCO's original and amended cost of service study and rate design filings, my testimony herein focuses upon the Cooperative's amended cost of service study and amended proposed rates.

Q. What costs has AEPCO used to form its proposed rate design?

A. The following table summarizes AEPCO's adjusted current and proposed amended test year revenues, operating expenses, net income (margins), and overall rates of return under current and AEPCO proposed rates. The table also provides a summary of Staff's adjusted revenue requirements under Staff proposed rates. AEPCO's current rates produce a positive margin of $14,139,018 and an overall rate of return of 6.10 percent when compared to its adjusted revenue requirement claims. Revenues under AEPCO's proposed rates would produce a positive margin of $14,042,263 and a positive overall rate of return of 6.06 percent. Staff's adjusted revenue requirement and rate base using current rates would produce a positive margin of $15,942,378 and 7.53 percent overall rate of return. Staff's adjusted proposed revenue requirement and rates would produce a positive margin of $16,173,394 and 7.64 percent overall rate of return.

As discussed below Staff witness Smith will address the various revenue requirement component allowances and adjustments; Staff witness Vickroy addresses the required net income allowance or margin, which he bases on a 1.35 Debt Service Coverage factor.

Table I – Cost of Service Summary				
	AEPCO Claim		Staff Adjusted	
Revenues	Current	Proposed	Current	Proposed
Electric Member Revenue	$166,618,638	$166,521,885	$166,618,638	$166,849,654
Non-Members	8,620,097	8,620,097	8,620,097	8,620,097
Other Operating Revenue	3,523,943	3,523,943	3,523,943	3,523,943
Total Operating Revenue	$178,762,678	$178,665,925	$178,762,678	$178,993,694
Operating Expenses	164,623,662	164,623,662	162,820,300	162,820,300
Operating Income (Margin)	$ 14,139,018	$ 14,042,263	$ 15,942,378	$ 16,173,394
Income Taxes	-	-	-	-
Net Income (Margin)	$ 14,139,018	$ 14,042,263	$ 15,942,378	$ 16,173,394
Rate Base	$231,844,975	$231,844,975	$211,802,594	$211,802,594
Rate of Return	6.10%	6.06%	7.53%	7.64%

Q. What is your understanding of AEPCO's proposed rate design?

A. Consistent with Commission requirements, AEPCO seeks approval of its proposed monthly Fixed Charge and O&M Charge rates and Energy Rates for Base Resources and Other Existing Resources to its ARM and partial requirements member ("PRM") customers. The following table summarizes AEPCO's and Staff's proposed rates, compared with current rates, along with the respective revenues and percentage increase under said proposals by ARM and PRM.

Table II- Current and Proposed AEPCO/STAFF RATES WITH % INCREASE					
		AEPCO Claim		STAFF Adjusted	
Services	Current	Proposed	% Inc.	Proposed	% Inc.
ARM Charges					
Demand Rate ($/kW)	$14.98	N/A		N/A	
Fixed Charge		$ 862,343		$ 931,105	
O&M Charge		$1,229,653		$1,178,484	
Energy: Base Resources ($/kWh)		$0.03236		$0.03234	
Energy: Other Existing Resources ($/kWh)		$0.06746		$0.06746	
Energy: Average ($/kWh)	$0.02073	$0.037222		$0.037211	
ARM Revenues	$60,386,767	$57,935,532	-4.06%	$58,137,179	-3.73%
PRM Charges – MEC					
Fixed Charge	$855,113	$ 709,721		$ 764,976	
O&M Charge (Current $/kW)	$7.26	$1,323,724		$1,274,882	
Energy: Base Resources ($/kWh)		$0.03216		$0.03215	
Energy: Other Existing Resources ($/kWh)		$0.06879		$0.06879	
Energy: Average ($/kWh)	$0.02073	$0.035954		$0.035943	
PRM Revenues MEC	$54,205,506	$55,874,756	3.08%	$55,941,934	3.20%
PRM Charges - SSVEC					
Fixed Charge	$757,429	$ 628,440		$ 677,366	
O&M Charge (Current $/kW)	$7.26	$1,172,125		$1,128,876	
Energy: Base Resources ($/kWh)		$0.03230		$0.03229	
Energy: Other Existing Resources ($/kWh)		$0.06676		$0.06676	
Energy: Average ($/kWh)	$0.02073	$0.036722		$0.036711	
PRM Revenues SSVEC	$52,026,365	$52,711,597	1.32%	$52,770,540	1.43%
Total Electric Member Revenues	$166,618,638	$166,521,885	-.06%	$166,849,654	.14%
Revenue Increase/(Decrease)		($96,753)		$231,015	

Q. Please describe AEPCO's allocated cost of service study and proposed rate design methods.

A. I have reviewed AEPCO's cost of service study and proposed rate design methods. AEPCO witness Gable prepared a fully allocated cost of service study based upon AEPCO's as-filed and amended electric generation revenue requirement study; *i.e.*, total pro forma operating expenses less other revenues plus its requested margin requirements. Witness Gable's direct and supplemental testimony explains the underlying process and methods he employed in preparing his study and proposed rate design. His original testimony (at pages 3-6) explains

the generally well-accepted functionalization, classification, and allocation process employed when preparing a fully allocated cost of service study. Further, he notes that his cost of service study methods resulted from significant input from AEPCO members, and reflects specific service generation resource obligations to its PRM and ARM members. Additionally, his supplemental testimony (at pages 2-3) explains that the parties have also agreed to shift Scheduling Revenues from the Additional ARM Resources O&M function to the Base Resources fixed cost function, and the parties have agreed to a shift of resource planning expenses from Base Resources O&M to Additional ARM O&M. His supplemental testimony also notes that members will need to consider the impact on rates that will occur once Trico Electric Cooperative, Inc. becomes a PRM. The outcome of that change would not be provided until the filing of the amended contracts. Witness Gable's original and amended studies explain in detail the elements of the claimed, underling revenue requirements and billing determinants, as they relate to the pro forma test period discussed by AEPCO witness Pierson in his testimony (presented in Schedules A through F).

Q. What is your opinion of AEPCO's fully allocated cost of service study and proposed rate design?

A. I have reviewed AEPCO witness Gables's testimony, supporting exhibits, workpapers, and AEPCO's answers to data requests. AEPCO provides the results of its fully allocated cost of service study in Schedules G of its rate filing. Schedule G-6 provides for the fully allocated revenue requirements by functionalization. AEPCO did so by using the categories of Base Resources, Other Existing Resources, and Additional ARM Resources. Each of these three categories has been further divided to break down Fixed, O&M, and Energy related costs. Schedule G-4 reflects the distributed functional costs on customer class bases. Schedule G-6 allocates the results on the basis of each customer classes' respective fixed cost and energy allocation factors (shown on Schedule G-7). Schedule G-4 provides the necessary rate

design based upon the fully distributed customer class functional cost; *i.e.*, customer class revenue requirement divided by each customer class' respective billing determinants (billing demands and base, other, and additional ARM resources kWh). Schedules G-1 and G-2 summarize the overall revenues under current and proposed rates, less operating expenses to reflect profit or margins and resultant overall rate of return, based upon net rate base values. The derivation of revenues under current and proposed rates is provided for in Schedules H-1 to H-5, which include detail by customer member and other related revenues.

I believe that AEPCO's amended fully allocated cost of service methods, including the underlying process and methods described and significant input from its members appear to be a reasonable basis for the development of the fully allocated cost of service study and rate design.

Q. Briefly describe your review process.

A. I validated all of AEPCO's allocated cost of service study calculations and the flow through of calculation results to the exhibits contained in AEPCO's amended filing. I reviewed the methods used to develop the underlying allocation factors, and I examined the allocated costs that resulted from the application of these factors to the amended revenue requirement elements for each rate-design component proposed by AEPCO. This review confirmed that the methods and approach here were reasonable and appropriately reflected in the amended filing. I also confirmed that the development of each rate was based upon the allocated revenue requirement for each generation service offered.

Q. Please identify the primary rates for which AEPCO requests Commission approval.

A. The primary rates identified by AEPCO in witness Gable's testimony are as follows:

Monthly Charges	MEC	SSVEC	ARM
Fixed Charge	$709,721	$628,440	$862,343
O&M Charge	$1,323,724	$1,172,125	$1,229,653
Base Energy Charge/kWh	$0.03216	$0.03230	$0.03236
Other Existing Resources Charge/kWh	$0.06879	$0.06676	$0.06746

Q. Are you recommending approval of AEPCO's above referenced fully allocated cost of service study and rate design as-filed and requested?

A. No. I have no reason to oppose AEPCO's fully allocated cost of service study methods. However, Staff witnesses Smith and Vickroy in their testimony have proposed various adjustments to AEPCO's pro forma test year revenue requirement such as operating expenses, other revenues, and net income (margin and overall rate of return). I have updated the fully allocated cost of service study using AEPCO's cost of service study methods to incorporate Staff witnesses Smith and Vickroy revenue requirement adjustments. The updated study includes my proposed rate design necessary to produce Staff's proposed revenue requirement. I attach them to my testimony as DMK-Schedules G and H, respectively. In order to provide for ease of comparison, I used the same Schedule G and H references as those in AEPCO witness Gable's testimony and supporting exhibits.

Q. How did you allocate staff witness Ralph's Smith's proposed expense adjustments?

A. DMK Schedules G-6, pages 3.1, 3.2 and 3.3 schedules set forth the methods I used to allocate Staff witness Smith's proposed expense adjustments from his Attachment RCS-2, Schedule C.1. Briefly, DMK Schedule G-6, p. 3.2 allocated Staff witness Smith's proposed $898,760 reduction to payroll and benefits (his adjustment C-1) based upon the ratio of AEPCO's allocated payroll and benefits claim by account for each of the three functional

areas (Base, Other Existing, and Additional ARM resources) to total payroll and benefits claim. The allocated adjustment by functional category is then carried forward onto DMK Schedule G-6, p. 3.1, in order to reflect the appropriate adjustment on an account by account bases. The total allocated payroll and benefits adjustment is also shown on DMK Schedule G-6, p. 3.3. DMK Schedule G-6, p. 3.3 also sets forth the functional allocation factors used and resultant allocated costs to each of the three functional categories.

As shown, Staff witness Smith's proposed downward adjustment of $681,900 in Incentive Compensation (C-2), $79,926 of Donations (C-3), and $112,240 of Lobbying Expenses (C-3) have been identified as A&G related. I have allocated them on the basis of the ratio of AEPCO's claimed A&G expense by functional category to the total A&G claim, excusive of payroll and benefits expenses. The resulting allocated adjustments are also carried forward and reflected in the A&G account by function category on DMK Schedule G-6, p. 3.1.

Staff witness Smith's proposed downward adjustment of $30,536 to depreciation expense (C-5a) is considered a direct reduction to base functional depreciation expense, while the $95,184 reduction for Accretion Expense (C-5b) was allocated to Other Interest functional categories based upon the same allocation ratio used by AEPCO. These downward adjustments proposed by Staff witness Smith are so reflected on DMK Schedule G-6, p. 3.3, the results of which have been carried forward on DMK Schedule G-6, p. 3.1.

Staff's proposed adjustments allocated by functional category on an account by account bases in DMK Schedule G-6, p. 3.1 have been incorporated into AEPCO's allocated revenue requirement claim by account, the results of which are shown on DMK Schedule G-6, p. 1 as Staff's Adjusted Distribution of Expenses by Resource. Finally, adjusted results as shown on DMK Schedule G-6, p. 1 have been fully incorporated into AEPCO's proposed cost of

service study allocation and rate design. Finally, DMK- Schedule A-1 provides a proof of revenue by rate class. It demonstrates that Staff's proposed rates and other revenues would produce approximately the same $231,014 revenue increase as reflected in Staff witness Smith's testimony at Attachment RCS-2, Schedule A, page 1, Column E, line 27.

For the reasons noted herein, I recommend adoption of Staff's proposed rates as summarized on Table II above.

Q. Do you have any other comments?

A. Yes, as noted earlier Trico has elected to convert its Class A member relationship with AEPCO to become a PRM customer. The impact of this change was not, however, provided as part of AEPCO's amended filing and supplemental testimony. On June 2, 2010 AEPCO filed amended ARM and PRM agreements with the Commission. Attached to these agreements as Exhibit D and appended hereto is a copy of the Summary of Revised Proposed Rates filed under that agreement. By way of example, the table below compares AEPCO's proposed April 20, 2010 ARM Fixed and O&M monthly charges to its June 2, 2010 rates shown on Exhibit D. The rates would be revised to reflect the remaining ARM customers' allocated share and rates; thus, the difference or balance is effectively Trico's proportional share and monthly rate.

	Fixed Charge	Fixed O&M
4/20/10 ARM	$862,343	$1,229,653
6/02/10 ARM	$232,978	$ 436,144
Balance Trico PRM	$629,365	$ 793,509

A preliminary review of the June 2, 2010 amended agreements indicates that the proposed rates are based upon the April 20, 2010 amended revenue requirement and follow some of the same general cost of service study allocation methods. However, I have not been able to fully verify all of the associated calculations and rates. Due to the timing of the June 2, 2010 filing, I would like to preserve the right to supplement my testimony to reflect an updated cost of service study and rate design analysis. This is necessary to confirm that the allocated cost of service study and proposed rate design are based upon the above referenced cost allocation and rate design methods. It is also necessary to incorporate Staff's recommended adjustments to AEPCO's pro forma test year revenue requirement claims.

Q. Does that conclude your direct testimony?

A. Yes it does.

Arizona Electric Power Cooperative, Inc.

COST OF SERVICE SUMMARY - PRESENT AND PROPOSED RATES - AEPCO vs. Staff Adjusted

		Current		AEPCO Proposed		Staff Proposed
All-Requirements						
Demand Rate per kW	$	14.98				
Fixed Charge			$	862,343		$931,105
O&M Charge			$	1,229,653		$1,178,484
Energy Rates						
Base Resources $/kWh			$	0.03236	$	0.03234
Other Existing Resources $/kWh			$	0.06746	$	0.06746
Energy Rate $/kWh	$	0.02073	$	0.037222	$	0.037211
Revenues		$60,386,767	$	57,935,532		$58,137,179
$Increase			$	(2,451,235)	$	(2,249,588)
% Increase				-4.06%		-3.73%
Partial-Requirements Members:						
Mohave Electric Cooperative						
Fixed Charge	$	855,113	$	709,721		$764,975
O&M Charge (Present $/kW)	$	7.26	$	1,323,724		$1,274,882
Energy Rates						
Base Resources $/kWh			$	0.03216	$	0.03215
Other Existing Resources $/kWh			$	0.06879	$	0.06879
Energy Rate $/kWh	$	0.02073	$	0.035954	$	0.035943
Revenues		$54,205,506	$	55,874,756		$55,941,934
$Increase			$	1,669,250	$	1,736,428
% Increase				3.08%		3.20%
Sulphur Springs Valley						
Fixed Charge	$	757,429	$	628,440		$677,366
O&M Charge (Present $/kW)	$	7.26	$	1,172,125		$1,128,876
Energy Rates						
Base Resources $/kWh			$	0.03230	$	0.03229
Other Existing Resources $/kWh			$	0.06676	$	0.06676
Energy Rate $/kWh	$	0.02073	$	0.036722	$	0.036711
Revenues		$52,026,365	$	52,711,597		$52,770,540
$Increase			$	685,232	$	744,175
% Increase				1.32%		1.43%
Total		$166,618,638		$166,521,885		$166,849,654
$Increase			$	(96,753)	$	231,015
% Increase				-0.06%		0.14%

Arizona Electric Power Cooperative, Inc.

COST OF SERVICE SUMMARY - PRESENT RATES - AEPCO vs. Staff Adjusted

LINE NO.	DESCRIPTION	PER AEPCO TOTAL AEPCO	PER STAFF TOTAL AEPCO
1	REVENUES:		
2	MEMBERS (a)	$166,618,638	$166,618,638
3	NON-MEMBERS (b)	8,620,097	8,620,097
4	OTHER OPERATING REVENUE (b)	3,523,943	3,523,943
5	TOTAL REVENUES	$178,762,678	$178,762,678
6	OPERATING EXPENSES (c)	164,623,662	162,820,300
7	ELECTRIC OPERATING MARGINS	$14,139,016	$15,942,378
8	INCOME TAXES	0	0
9	RETURN (MARGINS) (LINE 7 - LINE 8)	$14,139,016	$15,942,378
10			
11	RATE BASE (d)	$ 231,844,975	$ 211,802,594
12	RATE OF RETURN	6.10%	7.53%
13			
14			
15	SUPPORTING SCHEDULES:		
16	(a) AEPCO & Staff (DMK) H-1, LINE 1		
17	(b) AEPCO C-1, PAGE 3, LINES 3 AND 5		
18	(c) AEPCO & Staff (DMK) G-6, PAGE 1, LINE 50 AND C-1, PAGE 4, LINE 44		
19	(d) AEPCO B-1, LINE 9 & Staff Attachment RCS-2, Page 2, Line 33 Staff Proposed Rate Base		

Arizona Electric Power Cooperative, Inc.

COST OF SERVICE SUMMARY - PROPOSED RATES - AEPCO vs. Staff Adjusted

LINE NO.	DESCRIPTION	PER AEPCO TOTAL AEPCO	PER STAFF TOTAL AEPCO
1	REVENUES:		
2	MEMBERS (a)	$166,521,885	$166,849,654
3	NON-MEMBERS (b)	8,620,097	8,620,097
4	OTHER OPERATING REVENUE (b)	3,523,943	3,523,943
5	TOTAL REVENUES	$178,665,925	$178,993,694
6	OPERATING EXPENSES (c)	164,623,662	162,820,300
7	ELECTRIC OPERATING MARGINS	$14,042,263	$16,173,394
8	INCOME TAXES	0	0
9	RETURN (MARGINS) (LINE 6 - LINE 7)	$14,042,263	$16,173,394
10			
11	RATE BASE (d)	$ 231,844,975	$ 211,802,594
12	RATE OF RETURN	6.06%	7.64%
13			
14			
15	SUPPORTING SCHEDULES:		
16	(a) AEPCO & Staff (DMK) H-1, LINE 1		
17	(b) AEPCO C-1, PAGE 3, LINES 3 AND 5		
18	(c) AEPCO & Staff (DMK) G-6, PAGE 1, LINE 50 AND C-1, PAGE 4, LINE 44		
19	(d) AEPCO B-1, LINE 9 & Staff Attachment RCS-2, Page 2, Line 33 Staff Proposed Rate Base		

Arizona Electric Power Cooperative, Inc.

DERIVATION OF PROPOSED RATES - Staff Adjusted

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1					
2		SEE DMK SCHEDULE G-4, PAGE 1 OF 2			

Arizona Electric Power Cooperative, Inc.

RATE BASE ALLOCATION TO CLASSES OF SERVICE - Staff Adjusted

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1					
2		THIS SCHEDULE IS NOT APPLICABLE			

Arizona Electric Power Cooperative, Inc.

DERIVATION OF REVENUE REQUIREMENTS AND RATES - Staff Adjusted

LINE NO.	FUNCTIONAL COSTS	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1	REVENUE REQUIREMENT DEVELOPMENT				
2	FIXED COSTS				
3	BASE RESOURCES	$7,038,055	$6,232,021	$6,389,296	$19,659,373
4	OTHER EXISTING RESOURCES	2,141,647	1,896,375	1,944,233	5,982,255
5	ADDITIONAL ARM RESOURCES	0	0	2,839,729	2,839,729
6	SUB-TOTAL	$9,179,703	$8,128,396	$11,173,258	$28,481,356
7					
8	O&M				
9	BASE RESOURCES	$12,638,564	$11,191,130	$11,473,556	$35,303,250
10	OTHER EXISTING RESOURCES	2,660,026	2,355,386	2,414,828	7,430,239
11	ADDITIONAL ARM RESOURCES	0	0	253,422	253,422
12	SUB-TOTAL	$15,298,589	$13,546,516	$14,141,806	$42,986,911
13					
14	ENERGY				
15	BASE RESOURCES	$25,226,075	$23,835,642	$24,575,672	$73,637,389
16	OTHER EXISTING RESOURCES	6,237,567	7,259,986	8,011,534	21,509,087
17	ADDITIONAL ARM RESOURCES	0	0	234,910	234,910
18	SUB-TOTAL	$31,463,642	$31,095,628	$32,822,116	$95,381,386
19					
20	TOTAL RESOURCE COSTS				
21	BASE RESOURCES	$44,902,694	$41,258,794	$42,438,524	$128,600,012
22	OTHER EXISTING RESOURCES	11,039,240	11,511,746	12,370,594	34,921,581
23	ADDITIONAL ARM RESOURCES	0	0	3,328,061	3,328,061
24	SUB-TOTAL	$55,941,934	$52,770,540	$58,137,179	$166,849,654
25					
26					
27	RATE DEVELOPMENT				
28	BILLING DETERMINANTS				
29	BILLING DEMANDS	1,723,399	1,629,806	1,839,465	5,192,670
30	BASE RESOURCE KWH	784,700,545	738,282,902	759,805,654	2,282,789,101
31	OTHER EXISTING RESOURCES KWH	90,679,515	108,755,098	119,040,065	318,474,678
32	ADDITIONAL ARM RESOURCES KWH	0	0	3,200,000	3,200,000
33	TOTAL KWH	875,380,060	847,038,000	882,045,719	2,604,463,779
34					
35	MONTHLY CHARGES				
36	FIXED CHARGE	$764,975	$677,366	$931,105	$5.485
37	O&M CHARGE	$1,274,882	$1,128,876	$1,178,484	$8.278
38	BASE ENERGY CHARGE	$0.03215	$0.03229	$0.03234	$0.03226
39	OTHER EXISTING RESOURCE ENERGY CHARGE	$0.06879	$0.06676	$0.06746	$0.06754
40	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	$0.06746	$0.07341
41	AVERAGE ENERGY CHARGE	$0.035943	$0.036711	$0.037211	$0.036622

Arizona Electric Power Cooperative, Inc.

ASSIGNMENT OF BASE AND OTHER ENERGY RESOURCE COSTS AND CREDITS - Staff Adjusted

BASE RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	ENERGY	MEC	SSVEC	ARM
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	COAL COSTS FOR TARIFF LOAD	$19,329,841	$6,678,640	$6,187,018	$6,464,183
4	COAL COSTS FOR RESOURCE TRANSFERS	1,145,169	398,862	269,962	476,345
5	COAL COSTS FOR THIRD PARTY SALES	2,507,121	1,199,603	705,665	601,853
6	RESOURCE TRANSFER CREDITS	(1,699,172)	(572,118)	(405,130)	(721,924)
7	SUB-TOTAL	$21,282,959	$7,704,987	$6,757,515	$6,820,457
8					
9	BASE COST BEFORE ADJUSTMENTS	56,603,695	19,457,317	18,306,352	18,840,027
10					
11	PRODUCTION - FUEL A/C 501	$77,886,654	$27,162,304	$25,063,867	$25,660,484
12					
13	ADJUSTMENTS				
14	PURCHASED POWER ACCOUNT 555 - ENERGY	1,701,090	584,744	550,154	566,192
15	TRANSMISSION OF ELEC BY OTHERS ACCOUNT 565 - ENERGY	2,880	990	932	959
16	FIRM CONTRACT REVENUES	(2,448,992)	(841,832)	(792,035)	(815,125)
17	BASE RESOURCE ECONOMY ENERGY	(3,504,243)	(1,680,130)	(987,275)	(836,838)
18	SCHEDULING REVENUES	0	0	0	0
19	OTHER OPERATING REVENUES	0	0	0	0
20	TOTAL NET BASE RESOURCES ENERGY REVENUE REQUIREMENTS	$73,637,389	$25,226,075	$23,835,642	$24,575,672
21					
22					

OTHER RESOURCE ENERGY COSTS AND CREDITS

23					
24	DESCRIPTION	ENERGY	MEC	SSVEC	ARM
25	OTHER EXISTING RESOURCE COSTS	$21,509,087	$6,237,567	$7,259,986	$8,011,534
26	RESOURCE TRANSFER COSTS	1,699,172	272,834	749,346	676,992
27	OTHER RESOURCE COSTS	$19,809,915	$5,964,733	$6,510,640	$7,334,542
28					
29	RESOURCE TRANSFER KWH	35,966,376	5,616,722	15,907,156	14,442,498
30	OTHER RESOURCE KWH	282,508,302	85,062,793	92,847,942	104,597,567
31	TOTAL OTHER EXISTING RESOURCE KWH	318,474,678	90,679,515	108,755,098	119,040,065

Arizona Electric Power Cooperative, Inc.

DISTRIBUTION OF RATE BASE BY FUNCTION - Staff Adjusted

LINE NO.	DESCRIPTION	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES	TOTAL AEPCO
1					
2		THIS SCHEDULE IS NOT APPLICABLE			

Arizona Electric Power Cooperative, Inc.

Distribution of Expenses by Resource - Staff Adjusted (a)
(Reclassifications and Pro Forma Adjustments Included)

LINE NO.		TOTAL ADJUSTED O&M EXPENSES	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$77,906,029	$77,906,029	$0	$0
4	PRODUCTION - FUEL A/C 547	10,574,530	0	10,574,530	0
5	PRODUCTION - STEAM A/C 500	6,183,360	6,183,360	0	0
6	A/C 502	1,106,502	1,106,502	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	876,286	876,286	0	0
10	A/C 506 & 509	1,094,794	1,094,794	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	242,281	0	242,281	0
14	A/C 548	198,520	0	198,520	0
15	A/C 549	39,576	0	39,576	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY	0	0	0	0
18	- DEMAND A/C 555	3,117,006	751,678	0	2,365,328
19	- ENERGY A/C 555	13,428,376	1,701,090	11,492,376	234,910
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	2,539,437	2,225,793	310,523	3,120
22	A/C 557	0	0	0	0
23	TRANSMISSION		0	0	0
24	A/C 562	819	699	119	0
25	A/C 564	77	65	11	0
26	A/C 565	4,501,921	3,200,940	1,138,980	162,000
27	ADMINISTRATIVE & GENERAL	10,800,350	9,940,732	775,640	83,977
28	TOTAL OPERATIONS	$132,609,861	$104,987,969	$24,772,557	$2,849,335
29					
30	PRODUCTION - STEAM - A/C 510	$1,346,996	$1,346,996	$0	$0
31	A/C 511	27,649	27,649	0	0
32	A/C 512	4,018,147	4,018,147	0	0
33	A/C 513	5,638,224	5,638,224	0	0
34	A/C 514	2,390,050	2,390,050	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	52,802	0	52,802	0
37	A/C 552	3,190,952	0	3,190,952	0
38	A/C 553	1,746,819	0	1,746,819	0
39	A/C 554.	178,828	0	178,828	0
40	TRANSMISSION		0	0	0
41	A/C 570	13,900	11,874	2,026	0
42	GENERAL PLANT	355,096	325,750	25,022	4,325
43	TOTAL MAINTENANCE	$18,959,464	$13,758,690	$5,196,449	$4,325
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$8,317,632	$6,298,879	$1,993,016	$25,737
47	TAXES	2,933,343	2,617,177	316,166	0
48	TOTAL OTHER	$11,250,975	$8,916,056	$2,309,182	$25,737
49					
50	TOTAL OPERATING EXPENSES	$162,820,300	$127,662,715	$32,278,188	$2,879,397
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$10,812,194	$8,149,682	$2,653,298	$9,214
54	INT. CHARGES TO CONST.	(187,816)	(141,566)	(46,090)	(160)
55	OTHER INT. EXPENSE	1,047,090	847,554	193,845	5,690
56	OTHER DEDUCTIONS	151,174	113,947	37,098	129
57	TOTAL INT. & OTHER DED.	$11,822,642	$8,969,617	$2,838,151	$14,873
58					
59	TOTAL EXPENSES	$ 174,642,942	$ 136,632,333	$ 35,116,339	$ 2,894,270
60					
61					
62					
63	SUPPORTING SCHEDULES:				
64	(a) Sum of DMK Schedules G-6, PAGES 2, 3, 3.1 (Staff Adjustments) AND 4				
65					

Arizona Electric Power Cooperative, Inc.

Distribution of Booked Expenses by Resource - See Staff Note Below*

LINE NO.		TOTAL BOOKED O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$61,965,748	$61,965,748	$0	$0
4	PRODUCTION - FUEL A/C 547	10,574,530	0	10,574,530	0
5	PRODUCTION - STEAM A/C 500	5,997,229	5,997,229	0	0
6	A/C 502	2,795,766	2,795,766	0	0
7	A/C 503	0		0	0
8	A/C 504	0		0	0
9	A/C 505	1,385,698	1,385,698	0	0
10	A/C 506 & 509	1,083,857	1,083,857	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	234,983	0	234,983	0
14	A/C 548	707,145	0	707,145	0
15	A/C 549	39,148	0	39,148	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	6,274,506	751,678	2,925,000	2,597,828
19	- ENERGY A/C 555	35,795,431	1,701,090	30,545,119	3,549,222
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	3,315,542	2,906,043	405,426	4,074
22	A/C 557	1,548,021	1,356,826	189,293	1,902
23	TRANSMISSION				
24	A/C 562	819	699	119	0
25	A/C 564	77	65	11	0
26	A/C 565	16,345,082	14,201,775	1,981,307	162,000
27	ADMINISTRATIVE & GENERAL	11,249,966	10,299,504	791,139	159,323
28	TOTAL OPERATIONS	$159,313,546	$104,445,978	$48,393,220	$6,474,348
29					
30	PRODUCTION - STEAM - A/C 510	$1,302,263	$1,302,263	$0	$0
31	A/C 511	26,944	26,944	0	0
32	A/C 512	4,763,936	4,763,936	0	0
33	A/C 513	6,184,656	6,184,656	0	0
34	A/C 514	2,334,541	2,334,541	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	51,049	0	51,049	0
37	A/C 552	27,641	0	27,641	0
38	A/C 553	1,384,550	0	1,384,550	0
39	A/C 554.	175,654	0	175,654	0
40	TRANSMISSION				
41	A/C 570	13,624	11,638	1,986	0
42	GENERAL PLANT	304,878	279,120	21,440	4,318
43	TOTAL MAINTENANCE	$16,569,736	$14,903,098	$1,662,320	$4,318
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$7,883,883	$5,904,356	$1,960,365	$19,162
47	TAXES	0	0	0	0
48	TOTAL OTHER	$7,883,883	$5,904,356	$1,960,365	$19,162
49					
50	TOTAL OPERATING EXPENSES	$183,767,165	$125,253,432	$52,015,905	$6,497,828
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$10,580,757	$7,975,236	$2,596,504	$9,017
54	INT. CHARGES TO CONST.	(187,816)	(141,566)	(46,090)	(160)
55	OTHER INT. EXPENSE	781,804	589,284	191,854	666
56	OTHER DEDUCTIONS	151,174	113,947	37,098	129
57	TOTAL INT. & OTHER DED.	$11,325,919	$8,536,901	$2,779,365	$9,652
58					
59	TOTAL EXPENSES	$ 195,093,084	$ 133,790,334	$ 54,795,271	$ 6,507,480
60					
61	* STAFF NOTE - This Schedule is the same as filed by AEPCO				
62					
63	SUPPORTING SCHEDULES:				
64	(a) C-1, PAGES 1 AND 2				
65	(b) C-1, PAGE 2, LINES 44 + 50				

Arizona Electric Power Cooperative, Inc.

Distribution of Pro-Forma Adjustments by Resource - See Staff Note Below*

LINE NO.		ADJUSTMENTS TO O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$16,520,095	$16,520,095	$0	$0
4	PRODUCTION - FUEL A/C 547	0	0	0	0
5	PRODUCTION - STEAM A/C 500	354,307	354,307	0	0
6	A/C 502	35,855	35,855	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	0	0	0	0
10	A/C 506 & 509	20,818	20,818	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	13,891	0	13,891	0
14	A/C 548	1,405	0	1,405	0
15	A/C 549	816	0	816	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	(3,157,500)	0	(2,925,000)	(232,500)
19	- ENERGY A/C 555	(22,367,055)	0	(19,052,743)	(3,314,312)
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	109,150	95,669	13,347	134
22	A/C 557	0	0	0	0
23	TRANSMISSION				
24	A/C 562	0	0	0	0
25	A/C 564	0	0	0	0
26	A/C 565	(4,963,137)	(4,963,137)	0	0
27	ADMINISTRATIVE & GENERAL	540,635	477,180	60,665	2,790
28	TOTAL OPERATIONS	($12,890,718)	$12,540,789	($21,887,619)	($3,543,888)
29					
30	PRODUCTION - STEAM - A/C 510	$85,151	$85,151	$0	$0
31	A/C 511	1,342	1,342	0	0
32	A/C 512	(680,227)	(680,227)	0	0
33	A/C 513	(533,229)	(533,229)	0	0
34	A/C 514	105,663	105,663	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	3,337	0	3,337	0
37	A/C 552	3,164,043	0	3,164,043	0
38	A/C 553	376,795	0	376,795	0
39	A/C 554.	6,042	0	6,042	0
40	TRANSMISSION				
41	A/C 570	526	449	77	0
42	GENERAL PLANT	95,593	88,761	6,818	14
43	TOTAL MAINTENANCE	$2,625,037	($932,089)	$3,557,112	$14
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$464,285	$425,060	$32,650	$6,575
47	TAXES	0	0	0	0
48	TOTAL OTHER	$464,285	$425,060	$32,650	$6,575
49					
50	TOTAL OPERATING EXPENSES	($9,801,397)	$12,033,759	($18,297,857)	($3,537,299)
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$231,437	$174,445	$56,794	$197
54	INT. CHARGES TO CONST.	0	0	0	0
55	OTHER INT. EXPENSE	360,470	330,015	25,350	5,105
56	OTHER DEDUCTIONS	0	0	0	0
57	TOTAL INT. & OTHER DED.	$591,907	$504,461	$82,144	$5,302
58					
59	TOTAL EXPENSES	($9,209,490)	$12,538,220	($18,215,713)	($3,531,996)
60					
61	* STAFF NOTE - This Schedule is the same as filed by AEPCO				
62					
63	SUPPORTING SCHEDULES:				
64	(a) C-1, PAGES 3 & 4				
65	(b) C-1, PAGE 4, LINES 44 + 50				

Arizona Electric Power Cooperative, Inc.

Distribution of Pro-Forma Adjustments by Resource - Staff Proposed Expense Adjustments

LINE NO.		ADJUSTMENTS TO O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$ (28,439)	$ (28,439)	$ -	$ -
4	PRODUCTION - FUEL A/C 547	-	-	-	-
5	PRODUCTION - STEAM A/C 500	(168,177)	(168,177)	-	-
6	A/C 502	(17,019)	(17,019)	-	-
7	A/C 503	-	-	-	-
8	A/C 504	-	-	-	-
9	A/C 505	(0)	(0)	-	-
10	A/C 506 & 509	(9,882)	(9,882)	-	-
11	A/C 507	-	-	-	-
12	A/C 508	-	-	-	-
13	PRODUCTION - OTHER - A/C 546	(6,594)	-	(6,594)	-
14	A/C 548	(667)	-	(667)	-
15	A/C 549	(387)	-	(387)	-
16	A/C 550	-	-	-	-
17	OTHER POWER SUPPLY		-	-	-
18	- DEMAND A/C 555	-	-	-	-
19	- ENERGY A/C 555	-	-	-	-
20	- INDIRECT A/C 555	-	-	-	-
21	A/C 556	(51,810)	(45,411)	(6,335)	(64)
22	A/C 557	-	-	-	-
23	TRANSMISSION		-	-	-
24	A/C 562	-	-	-	-
25	A/C 564	-	-	-	-
26	A/C 565	-	-	-	-
27	ADMINISTRATIVE & GENERAL	(1,254,542)	(1,077,913)	(94,750)	(81,879)
28	TOTAL OPERATIONS	$ (1,537,517)	$ (1,346,841)	$ (108,733)	$ (81,943)
29					
30	PRODUCTION - STEAM - A/C 510	$ (40,418)	$ (40,418)	$ -	$ -
31	A/C 511	(637)	(637)	-	-
32	A/C 512	(65,562)	(65,562)	-	-
33	A/C 513	(13,203)	(13,203)	-	-
34	A/C 514	(50,155)	(50,155)	-	-
35	A/C 515.	-	-	-	-
36	PRODUCTION - OTHER - A/C 551	(1,584)	-	(1,584)	-
37	A/C 552	(732)	-	(732)	-
38	A/C 553	(14,526)	-	(14,526)	-
39	A/C 554.	(2,868)	-	(2,868)	-
40	TRANSMISSION		-	-	-
41	A/C 570	(250)	(213)	(36)	-
42	GENERAL PLANT	(45,374)	(42,132)	(3,236)	(6)
43	TOTAL MAINTENANCE	$ (235,309)	$ (212,319)	$ (22,983)	$ (6)
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$ (30,536)	$ (30,536)		
47	TAXES	-			
48	TOTAL OTHER	$ (30,536)	$ (30,536)	$ -	$ -
49					
50	TOTAL OPERATING EXPENSES	$ (1,803,362)	$ (1,589,697)	$ (131,716)	$ (81,949)
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$ -			
54	INT. CHARGES TO CONST.	-			
55	OTHER INT. EXPENSE	(95,184)	(71,745)	(23,358)	(81)
56	OTHER DEDUCTIONS	-			
57	TOTAL INT. & OTHER DED.	$ (95,184)	$ (71,745)	$ (23,358)	$ (81)
58					
59	TOTAL EXPENSES	$ (1,898,546)	$ (1,661,442)	$ (155,074)	$ (82,030)
60					
61					
62					
63	SUPPORTING SCHEDULES:				
64	(a) DMK Sch. G-6 PAGES 3.2 & 3.3				
65					

Arizona Electric Power Cooperative, Inc.

Distribution of Staff Payroll and Benefit Adjustment to O&M Expense Accounts

		AEPCO Distribution of Adjusted Payroll by Resource				Dist. of Staff Payroll/Benefits/Incentive C-1 Adj. by Resource			
Line	Account Description	Adjusted Payroll	Base	Other Existing Resources	Additional ARM Resources	Adjustments Payroll	Base	Other Existing Resources	Additional ARM Resources
1	OPERATING EXPENSES:								
2	OPERATIONS								
3	PRODUCTION - FUEL A/C 501	$769,808	$769,808	$0	$0	($28,439)	($28,439)	$0	$0
4	PRODUCTION - FUEL A/C 547	0	0	0	0	0	0	0	0
5	PRODUCTION - STEAM A/C 500	4,552,260	4,552,260	0	0	(168,177)	(168,177)	0	0
6	A/C 502	460,682	460,682	0	0	(17,019)	(17,019)	0	0
7	A/C 503					0	0	0	0
8	A/C 504					0	0	0	0
9	A/C 505	0	0	0	0	(0)	(0)	0	0
10	A/C 506 & 509	267,481	267,481	0	0	(9,882)	(9,882)	0	0
11	A/C 507					0	0	0	0
12	A/C 508					0	0	0	0
13	PRODUCTION - OTHER - A/C 546	178,481	0	178,481	0	(6,594)	0	(6,594)	0
14	A/C 548	18,048	0	18,048	0	(667)	0	(667)	0
15	A/C 549	10,479	0	10,479	0	(387)	0	(387)	0
16	A/C 550					0	0	0	0
17	OTHER POWER SUPPLY					0	0	0	0
18	- DEMAND A/C 555	0	0	0	0	0	0	0	0
19	- ENERGY A/C 555	0	0	0	0	0	0	0	0
20	- INDIRECT A/C 555	0	0	0	0	0	0	0	0
21	A/C 556	1,402,401	1,229,192	171,486	1,723	(51,810)	(45,411)	(6,335)	(64)
22	A/C 557	0	0	0	0	0	0	0	0
23	TRANSMISSION	0	0	0	0	0	0	0	0
24	A/C 562	0	0	0	0	0	0	0	0
25	A/C 564	0	0	0	0	0	0	0	0
26	A/C 565	0	0	0	0	0	0	0	0
27	ADMINISTRATIVE & GENERAL	10,298,856	9,562,837	734,554	1,465	(380,476)	(353,285)	(27,137)	(54)
28	TOTAL OPERATIONS	$17,958,496	$16,842,260	$1,113,048	$3,188	($663,451)	($622,213)	($41,120)	($118)
29						0	0	0	0
30	PRODUCTION - STEAM - A/C 510	1,094,051	1,094,051	0	0	(40,418)	(40,418)	0	0
31	A/C 511	17,237	17,237	0	0	(637)	(637)	0	0
32	A/C 512	1,774,656	1,774,656	0	0	(65,562)	(65,562)	0	0
33	A/C 513	357,375	357,375	0	0	(13,203)	(13,203)	0	0
34	A/C 514	1,357,599	1,357,599	0	0	(50,155)	(50,155)	0	0
35	A/C 515.					0	0	0	0
36	PRODUCTION - OTHER - A/C 551	42,879	0	42,879	0	(1,584)	0	(1,584)	0
37	A/C 552	19,823	0	19,823	0	(732)	0	(732)	0
38	A/C 553	393,202	0	393,202	0	(14,526)	0	(14,526)	0
39	A/C 554.	77,630	0	77,630	0	(2,868)	0	(2,868)	0
40	TRANSMISSION					0	0	0	0
41	A/C 570	6,757	5,772	985	0	(250)	(213)	(36)	0
42	GENERAL PLANT	1,228,209	1,140,434	87,601	175	(45,374)	(42,132)	(3,236)	(6)
43	TOTAL MAINTENANCE	$6,369,418	$5,747,125	$622,119	$175	($235,309)	($212,319)	($22,983)	($6)
44									
45	TOTAL LABOR	$24,327,914	$22,589,385	$1,735,167	$3,362	($898,760)	($834,533)	($64,103)	($124)
46									
47	PAYROLL ALLOCATOR 1	100.000%	92.853%	7.132%	0.014%	($898,760) Staff C-1 Adj. Net Decrease In Labor Expenses			
48	PAYROLL ALLOCATOR 2	5.049%	4.688%	0.360%		Allocated based upon ratio of As-filed account $/Total Labor$			
		100.000%	92.854%	7.132%	0.014%				
		100.000%	92.867%	7.133%					

Arizona Electric Power Cooperative, Inc.

Distribution of Pro-Forma Adjustments by Resource - Staff Adjustments

Staff Adj.	Description	Staff Alloc. Factor Ref.	Dist. of Staff Adjustments by Resource: Staff Adjustments	Base	Other Existing Resources	Additional ARM Resources	Proof
C-1	Var. Accts. Payroll Related Adjustments	See G-6,p3.2, L45	$ (898,760)	$ (834,533)	$ (64,103)	$ (124)	(0)
C-2	A&G - Removal of Incentive Compensation	A-2	$ (681,900)	$ (565,316)	$ (52,748)	$ (63,836)	0
C-3	A&G - Removal of Donations Expenses	A-2	$ (79,926)	$ (66,261)	$ (6,183)	$ (7,482)	0
C-4	A&G - Removal of Lobbying Expenses	A-2	$ (112,240)	$ (93,051)	$ (8,682)	$ (10,507)	0
C-5a	Depr. - ST2 & ST3 Reduction In Depr. Exp.	A-3	$ (30,536)	$ (30,536)	$ -	$ -	0
C-5b	Other. Int. Exp - Reductrion In Accretion Exp.	A-4	$ (95,184)	$ (71,745)	$ (23,358)	$ (81)	0
	Total Staff Expense Adjustments		$ (1,898,546)	$ (1,661,442)	$ (155,074)	$ (82,030)	(0)
	Development of Staff Allocation Factors						
	Total Admin & General	AEPCO G-6,p1,L27	$ 12,054,892	$ 11,018,645	$ 870,391	$ 165,856	0
	Payroll Expenses	See G-6,p3.2,L27	10,298,856	9,562,837	734,554	1,465	0
	A&G Net Of Payroll		$ 1,756,036	$ 1,455,808	$ 135,837	$ 164,391	0
	Staff Allocation Factor	A-2	100%	82.90%	7.74%	9.36%	0
	ST2 & ST3 Depr. Direct Staff Alloc. Factor	A-3	100%	100.00%	0.00%	0.00%	0
	Int. On Long Term Debt -AEPCO G-6,p2 L53	AEPCO G-6,p2,L53	$10,580,757	$7,975,236	$2,596,504	$9,017	0
	Staff Allocation Factor	A-4	100%	75.37%	24.54%	0.09%	(0)

Arizona Electric Power Cooperative, Inc.

Distribution of Expense Reclassifications by Resource - See Staff Note Below*

LINE NO.		RECLASSIFICATIONS OF O&M EXPENSES	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	($551,375)	(551,375)	$0	$0
4	PRODUCTION - FUEL A/C 547	0	0	0	0
5	PRODUCTION - STEAM A/C 500	0	0	0	0
6	A/C 502	(1,708,100)	(1,708,100)	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	(509,412)	(509,412)	0	0
10	A/C 506 & 509	0	0	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	0	0	0	0
14	A/C 548	(509,363)	0	(509,363)	0
15	A/C 549	0	0	0	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	0	0		
19	- ENERGY A/C 555	0	0	0	0
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	(833,446)	(730,508)	(101,914)	(1,024)
22	A/C 557	(1,548,021)	(1356826)	(189293)	(1902)
23	TRANSMISSION				
24	A/C 562	0	0	0	0
25	A/C 564	0	0	0	0
26	A/C 565	(6,880,024)	(6,037,697)	(842,327)	0
27	ADMINISTRATIVE & GENERAL	264,291	241,962	18,586	3,743
28	TOTAL OPERATIONS	($12,275,450)	($10,651,957)	($1,624,310)	$817
29					
30	PRODUCTION - STEAM - A/C 510	$0	$0	$0	$0
31	A/C 511	0	0	0	0
32	A/C 512	0	0	0	0
33	A/C 513	0	0	0	0
34	A/C 514	0	0	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	0	0	0	0
37	A/C 552	0	0	0	0
38	A/C 553	0	0	0	0
39	A/C 554.	0	0	0	0
40	TRANSMISSION				
41	A/C 570	0	0	0	0
42	GENERAL PLANT	0	0	0	0
43	TOTAL MAINTENANCE	$0	$0	$0	$0
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$0	$0	$0	$0
47	TAXES	2,933,343	2,617,177	316,166	0
48	TOTAL OTHER	$2,933,343	$2,617,177	$316,166	$0
49					
50	TOTAL OPERATING EXPENSES	($9,342,107)	($8,034,780)	($1,308,144)	$817
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$0	$0	$0	$0
54	INT. CHARGES TO CONST.	0	0	0	0
55	OTHER INT. EXPENSE	0	0	0	0
56	OTHER DEDUCTIONS	0	0	0	0
57	TOTAL INT. & OTHER DED.	$0	$0	$0	$0
58					
59	TOTAL EXPENSES	($9,342,107)	($8,034,780)	($1,308,144)	$817
60					
61	* STAFF NOTE - This Schedule is the same as filed by AEPCO				
62					
63	SUPPORTING SCHEDULES:				
64	(a) C-2, PAGES 1 & 2				
65	(b) C-2, PAGE 2, LINES 44 + 50				

Arizona Electric Power Cooperative, Inc.

Class A Member Revenue Requirements by Function - Staff Adjusted

LINE NO.		BASE RESOURCES			OTHER EXISTING RESOURCES			ADDITIONAL ARM RESOURCES			TOTAL AEPCO REVENUE REQUIREMENT			
		FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	Total
1	OPERATING EXPENSES:													
2	OPERATIONS													
3	PRODUCTION - FUEL A/C 501	$19,375	$0	$77,886,654	$0	$0	$0	$0	$0	$0	$19,375	$0	$77,886,654	$77,906,029
4	PRODUCTION - FUEL A/C 547	0	0	0	109,790	0	10,464,740	0	0	0	109,790	0	10,464,740	10,574,530
5	PRODUCTION - STEAM A/C 500	0	6,183,360	0	0	0	0	0	0	0	0	6,183,360	0	6,183,360
6	A/C 502	1,123,521	(17,019)	0	0	0	0	0	0	0	1,123,521	(17,019)	0	1,106,502
7	A/C 503	0	0	0	0	0	0	0	0	0	0	0	0	0
8	A/C 504	0	0	0	0	0	0	0	0	0	0	0	0	0
9	A/C 505	92,400	783,886	0	0	0	0	0	0	0	92,400	783,886	0	876,286
10	A/C 506 & 509	0	1,094,794	0	0	0	0	0	0	0	0	1,094,794	0	1,094,794
11	A/C 507	0	0	0	0	0	0	0	0	0	0	0	0	0
12	A/C 508	0	0	0	0	0	0	0	0	0	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	0	0	0	0	242,281	0	0	0	0	0	242,281	0	242,281
14	A/C 548	0	0	0	79,166	119,354	0	0	0	0	79,166	119,354	0	198,520
15	A/C 549	0	0	0	0	39,576	0	0	0	0	0	39,576	0	39,576
16	A/C 550	0	0	0	0	0	0	0	0	0	0	0	0	0
17	OTHER POWER SUPPLY													
18	- DEMAND A/C 555	751,678	0	0	0	0	0	2,365,328	0	0	3,117,006	0	0	3,117,006
19	- ENERGY A/C 555	0		1,701,090	0	0	11,492,376	0	0	234,910	0	0	13,428,376	13,428,376
20	- INDIRECT A/C 555	0	0	0	0	0	0	0	0	0	0	0	0	0
21	A/C 556	0	2,225,793	0	0	310,523	0	0	3,120	0	0	2,539,437	0	2,539,437
22	A/C 557	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TRANSMISSION													
24	A/C 562	0	699	0	0	119	0	0	0	0	0	819	0	819
25	A/C 564	0	65	0	0	11	0	0	0	0	0	77	0	77
26	A/C 565	0	3,198,060	2,880	0	1,138,980	0	0	162,000	0	0	4,499,040	2,880	4,501,921
27	ADMINISTRATIVE & GENERAL	0	9,940,732	0		775,640	0	0	83,977	0	0	10,800,350	0	10,800,350
28	TOTAL OPERATIONS	$1,986,974	$23,410,371	$79,590,624	$188,956	$2,626,485	$21,957,116	$2,365,328	$249,097	$234,910	$4,541,257	$26,285,954	$101,782,650	$132,609,861
29														
30	PRODUCTION - STEAM - A/C 510	0	1,346,996	0	0	0	0	0	0	0	0	1,346,996	0	1,346,996
31	A/C 511	0	27,649	0	0	0	0	0	0	0	0	27,649	0	27,649
32	A/C 512	0	4,018,147	0	0	0	0	0	0	0	0	4,018,147	0	4,018,147
33	A/C 513	0	5,638,224	0	0	0	0	0	0	0	0	5,638,224	0	5,638,224
34	A/C 514	0	2,390,050	0	0	0	0	0	0	0	0	2,390,050	0	2,390,050
35	A/C 515.	0	0	0	0	0	0	0	0	0	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	0	0	0	0	52,802	0	0	0	0	0	52,802	0	52,802
37	A/C 552	0	0	0	0	3,190,952	0	0	0	0	0	3,190,952	0	3,190,952
38	A/C 553	0	0	0	0	1,746,819	0	0	0	0	0	1,746,819	0	1,746,819
39	A/C 554.	0	0	0	0	178,828	0	0	0	0	0	178,828	0	178,828
40	TRANSMISSION													
41	A/C 570	0	11,874	0	0	2,026	0	0	0	0	0	13,900	0	13,900
42	GENERAL PLANT	0	325,750	0	0	25,022	0	0	4,325	0	0	355,096	0	355,096
43	TOTAL MAINTENANCE	$0	$13,758,690	$0	$0	$5,196,449	$0	$0	$4,325	$0	$0	$18,959,464	$0	$18,959,464
44														
45	OTHER:													
46	DEPRECIATION & AMORTIZATION	$6,298,879	$0	$0	$1,993,016	$0	$0	$25,737	$0	$0	8,317,632	0	0	8,317,632
47	TAXES	2,617,177	0	0	316,166	0	0	0	0	0	2,933,343	0	0	2,933,343
48	TOTAL OTHER	$8,916,056	$0	$0	$2,309,182	$0	$0	$25,737	$0	$0	$11,250,975	$0	$0	$11,250,975
49														
50	TOTAL OPERATING EXPENSES	$10,903,030	$37,169,061	$79,590,624	$2,498,138	$7,822,934	$21,957,116	$2,391,065	$253,422	$234,910	$15,792,232	$45,245,417	$101,782,650	$162,820,300
51														
52	INT. & OTHER DEDUCTIONS:													
53	INT. ON LONG-TERM DEBT	$8,149,682	$0	$0	$2,653,298	$0	$0	$9,214	$0	$0	$10,812,194	$0	$0	$10,812,194
54	INT. CHARGES TO CONST.	(141,566)	0	0	(46,090)	0	0	(160)	0	0	(187,816)	0	0	(187,816)
55	OTHER INT. EXPENSE	847,554	0	0	193,845	0	0	5,690	0	0	1,047,090	0	0	1,047,090
56	OTHER DEDUCTIONS	113,947	0	0	37,098	0	0	129	0	0	151,174	0	0	151,174
57	TOTAL INT. & OTHER DED.	$8,969,617	$0	$0	$2,838,151	$0	$0	$14,873	$0	$0	$11,822,642	$0	$0	$11,822,642
58														
59	TOTAL EXPENSES	$19,872,647	$37,169,061	$79,590,624	$5,336,289	$7,822,934	$21,957,116	$2,405,938	$253,422	$234,910	$27,614,874	$45,245,417	$101,782,650	$174,642,942
60														
61	REVENUE CREDITS													
62	FIRM CONTRACT REVENUES	$1,430,539	$0	$2,448,992	$0	$0	$0	$0	$0	$0	$1,430,539	$0	$2,448,992	$3,879,531
63	ECONOMY ENERGY	0	0	3,504,243	0	0	448,029	0	0	0	0	0	3,952,272	3,952,272
64	SCHEDULING REVENUES (all to ARMs)	788,294	0	0	0	0	0	0	0	0	788,294	0	0	788,294
65	OTHER OPERATING REVENUES	997,566	1,865,811	0	267,871	392,695	0	0	0	0	1,265,437	2,258,506	0	3,523,943
66	TOTAL REVENUE CREDITS	$3,216,399	$1,865,811	$5,953,235	$267,871	$392,695	$448,029	$0	$0	$0	$3,484,270	$2,258,506	$6,401,264	$12,144,040
67														
68	MARGINS	3,003,124	0	0	913,837	0	0	433,791	0	0	4,350,752	0	0	4,350,752
69														
70	CLASS A MEMBER REVENUE REQUIREMENTS	$ 19,659,373	$ 35,303,250	$ 73,637,389	$ 5,982,255	$ 7,430,239	$ 21,509,087	$ 2,839,729	$253,422	$ 234,910	$ 28,481,356	$ 42,986,911	$ 95,381,386	$ 166,849,654

Arizona Electric Power Cooperative, Inc.

DERIVATION OF ALLOCATION FACTORS - Staff Adjusted

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1	ALLOCATION FACTORS				
2	ENERGY ALLOCATION FACTORS				
3	BASE RESOURCE KWH	784,700,545	738,282,902	759,805,654	2,282,789,101
4	OTHER EXISTING RESOURCES KWH	90,679,515	108,755,098	119,040,065	318,474,678
5	ADDITIONAL ARM RESOURCES KWH	0	0	3,200,000	3,200,000
6					
7	BASE RESOURCE KWH	34.375%	32.341%	33.284%	100.000%
8	OTHER EXISTING RESOURCES KWH	28.473%	34.149%	37.378%	100.000%
9	ADDITIONAL ARM RESOURCES KWH	0.000%	0.000%	100.000%	100.000%
10					
11	FIXED COST ALLOCATION FACTORS				
12	ACP	35.800%	31.700%	32.500%	100.000%
13					
14					
15	FUNCTIONALIZATION FACTORS	BASE RESOURCES	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES	TOTAL AEPC
16	DISPATCHED ENERGY (KWH)	2,282,789,101	318,474,678	3,200,000	2,604,463,779
17	DISPATCHED ENERGY (%)	87.649%	12.228%	0.123%	100.000%
18					
19	SUB-TOTAL PURCHASED POWER				
20	PRODUCTION - FUEL A/C 501	$61,965,748	$0	$0	$61,965,748
21	PRODUCTION - FUEL A/C 547	0	10,574,530	0	10574530.1
22	SUBTOTAL ($)	$61,965,748	$10,574,530	$0	$72,540,278
23	SUBTOTAL (%)	85.423%	14.577%	0.000%	100.000%
24					
25	PAYROLL EXCLUDING A&G AND GEN PLT MNTC ($)	$10,961,004	$841,952	$1,589	$11,804,545
26	PAYROLL EXCLUDING A&G AND GEN PLT MNTC (%)	92.854%	7.132%	0.013%	100.000%
27					
28	INTEREST ON LONG TERM DEBT ($)	$7,975,236	$2,596,504	$9,017	$10,580,757
29	INTEREST ON LONG TERM DEBT (%)	75.375%	24.540%	0.085%	100.000%
30					
31	TOTAL EXPENSES LESS A&G ($)	$126,691,600	$34,340,699	$2,810,293	$163,842,592
32	TOTAL EXPENSES LESS A&G (%)	77.325%	20.960%	1.715%	100.000%
33					
34	A&G EXPENSES ($)	$10,299,504	$791,139	$159,323	$11,249,966
35	A&G EXPENSES (%)	91.551%	7.032%	1.416%	100.000%

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class - Staff Adjusted

March 31, 2009 Adjusted Test Year

Line No.	CLASS OF SERVICE	PRESENT	AEPCO PROPOSED	AEPCO INCREASE	AEPCO PERCENT	STAFF PROPOSED	STAFF INCREASE	STAFF PERCENT
1	Total Class A Member Revenues	$166,618,638	$166,521,885	($96,753)	-0.06%	$166,849,654	$231,015	0.14%
2	Non-Members	8,620,097	8,620,097	0	0.00%	8,620,097	0	0.00%
3	Other Operating Revenues	3,523,943	3,523,943	(0)	0.00%	3,523,943	0	0.00%
4	Total AEPCO	$178,762,678	$178,665,925	($96,753)	($0)	$178,993,694	$231,015	0.13%

Note: Revenues stated using synchronized FPPCA.

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class - Staff Adjusted
March 31, 2009 Adjusted Test Year

Line No.	CLASS OF SERVICE	CUSTOMERS	KWH CONSUMPTION	BILLING KW	REVENUE PRESENT	REVENUE PROPOSED	PROPOSED INCREASE ($)	PROPOSED INCREASE (%)
1	Member Contracts:							
2	Anza	1	51,283,408	96,412	$3,353,127	$3,236,743	($116,384)	-3.47%
3	Duncan	1	28,079,760	57,180	1,901,744	1,836,750	(64,994)	-3.42%
4	Graham	1	156,396,015	324,562	10,683,325	10,334,603	(348,721)	-3.26%
5	Mohave	1	875,380,060	1,723,399	54,205,506	55,941,934	1,736,428	3.20%
6	Sulphur	1	847,038,000	1,629,806	52,026,365	52,770,540	744,175	1.43%
7	Trico	1	646,286,536	1,361,311	44,448,572	42,729,083	(1,719,488)	-3.87%
8	Total Class A Members	6	2,604,463,779	5,192,670	$166,618,638	$166,849,654	$231,015	0.14%
9								
10	Other Firm Contracts:							
11	City of Mesa	0	0	0	$0	$0	N/A	N/A
12	Salt River Project	0	0	0	0	0	N/A	N/A
13	Public Service Company of New Mexico	0	0	0	0	0	N/A	N/A
14	ED2	1	68,952,281	96,000	3,879,531	3,879,531	$0	0.00%
15	Total Firm Contracts	1	68,952,281	96,000	$3,879,531	$3,879,531	$0	0.00%
16								
17	Total AEPCO	7	2,673,416,060	5,288,670	$170,498,169	$170,729,184	$231,015	0.14%

Note: Revenues stated using synchronized FPPCA.

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER BOOKED SALES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	ANZA													
2	MW	5.712	7.488	10.608	10.404	9.948	9.684	6.852	5.388	8.860	8.093	7.071	6.304	96.412
3	MWH	3,733.956	3,974.280	4,547.868	5,266.380	5,087.034	4,309.788	3,861.588	3,682.884	4,682.804	4,126.590	3,963.021	4,047.215	51,283.408
4														
5	DUNCAN													
6	MW	3.860	6.040	6.960	5.940	6.620	5.360	4.020	2.780	4.300	3.900	3.900	3.500	57.180
7	MWH	2,004.660	2,422.840	3,223.350	2,960.420	2,955.880	2,300.600	1,919.560	1,905.850	2,292.120	2,226.640	1,883.390	1,984.450	28,079.760
8														
9	GRAHAM													
10	MW	20.966	31.511	39.951	39.726	36.986	32.263	24.988	18.448	20.642	19.992	18.818	20.271	324.562
11	MWH	10,775.112	12,244.130	18,499.166	17,976.098	17,655.323	13,801.595	11,076.763	10,334.556	12,000.020	11,134.378	9,221.331	11,677.543	156,396.015
12														
13	MOHAVE													
14	MW	95.000	103.000	110.000	132.000	133.000	124.000	102.000	72.000	79.000	79.000	75.000	54.000	1,158.000
15	MWH	62,986.000	66,854.000	69,860.000	77,273.000	77,009.000	68,313.000	58,371.000	45,187.000	48,485.000	46,549.000	40,805.000	39,120.000	700,812.000
16														
17	SULPHUR													
18	MW	84.000	88.000	102.000	96.000	97.000	100.000	89.000	77.000	97.000	97.000	104.000	91.000	1,122.000
19	MWH	56,633.000	61,631.000	61,830.000	61,828.000	62,148.000	59,310.000	55,640.000	48,978.000	56,895.000	57,703.000	53,357.000	56,528.000	692,481.000
20														
21	TRICO													
22	MW	85.694	125.853	164.497	149.759	155.557	140.957	116.234	91.507	90.195	85.104	80.967	72.836	1,359.160
23	MWH	43,348.839	49,883.272	69,143.826	72,230.849	72,594.073	62,002.723	50,728.275	42,934.549	49,950.664	48,018.911	41,759.997	43,690.558	646,286.536
24														
25														
26														
27	FULL REQUIREMENTS													
28	MW	116.232	170.892	222.016	205.829	209.111	188.264	152.094	118.123	123.997	117.089	110.756	102.911	1,837.314
29	MWH	59,862.567	68,524.522	95,414.210	98,433.747	98,292.310	82,414.706	67,586.186	58,857.839	68,925.608	65,506.519	56,827.739	61,399.766	882,045.719
30														
31	PARTIAL REQUIREMENTS													
32	MW	179.000	191.000	212.000	228.000	230.000	224.000	191.000	149.000	176.000	176.000	179.000	145.000	2,280.000
33	MWH	119,619.000	128,485.000	131,690.000	139,101.000	139,157.000	127,623.000	114,011.000	94,165.000	105,380.000	104,252.000	94,162.000	95,648.000	1,393,293.000
34														
35														
36														
37	TOTAL CLASS A													
38	MW	295.232	361.892	434.016	433.829	439.111	412.264	343.094	267.123	299.997	293.089	289.756	247.911	4,117.314
39	MWH	179,481.567	197,009.522	227,104.210	237,534.747	237,449.310	210,037.706	181,597.186	153,022.839	174,305.608	169,758.519	150,989.739	157,047.766	2,275,338.719

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED SALES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	ANZA													
2	MW	5.712	7.488	10.608	10.404	9.948	9.684	6.852	5.388	8.860	8.093	7.071	6.304	96.412
3	MWH	3,733.956	3,974.280	4,547.868	5,266.380	5,087.034	4,309.788	3,861.588	3,682.884	4,682.804	4,126.590	3,963.021	4,047.215	51,283.408
4														
5	DUNCAN													
6	MW	3.860	6.040	6.960	5.940	6.620	5.360	4.020	2.780	4.300	3.900	3.900	3.500	57.180
7	MWH	2,004.660	2,422.840	3,223.350	2,960.420	2,955.880	2,300.600	1,919.560	1,905.850	2,292.120	2,226.640	1,883.390	1,984.450	28,079.760
8														
9	GRAHAM													
10	MW	20.966	31.511	39.951	39.726	36.986	32.263	24.988	18.448	20.642	19.992	18.818	20.271	324.562
11	MWH	10,775.112	12,244.130	18,499.166	17,976.098	17,655.323	13,801.595	11,076.763	10,334.556	12,000.020	11,134.378	9,221.331	11,677.543	156,396.015
12														
13	MOHAVE													
14	MW	131.516	139.516	146.516	168.516	169.516	160.516	138.516	108.516	115.516	114.800	110.800	89.800	1,594.044
15	CHEMSTAR O&M ADJ	0.000	0.000	0.000	0.000	0.000	(2.270)	0.000	0.000	0.000	(2.270)	0.000	(2.270)	(6.810)
16	POWER FACTOR ADJ	0.672	0.793	1.155	0.938	0.886	0.458	0.223	0.133	0.000	0.000	0.033	0.144	5.435
17	SCHED B O&M ADJ	0.000	23.765	33.100	11.400	10.300	19.000	8.800	0.300	3.600	3.065	5.400	12.000	130.730
18	ADJ MW	132.188	164.074	180.771	180.854	180.702	177.704	147.539	108.949	119.116	115.595	116.233	99.674	1,723.399
19	ENERGY MIN ADJ	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	12.000	4.000	39.000	4.000	59.000
20	ADJUSTED MWH	77,807.200	82,169.240	84,665.830	92,587.670	92,324.240	83,134.200	73,886.240	60,008.200	63,812.240	59,870.600	52,872.800	52,441.600	875,380.060
21														
22	SULPHUR													
23	MW	116.334	120.334	134.334	128.334	129.334	132.334	121.334	109.334	129.334	128.700	135.700	122.700	1,508.106
24	POWER FACTOR ADJ	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	SCHED B O&M ADJ	14.800	17.600	12.700	11.400	8.400	3.600	10.800	9.000	12.200	12.000	3.000	6.200	121.700
26	ADJ MW	131.134	137.934	147.034	139.734	137.734	135.934	132.134	118.334	141.534	140.700	138.700	128.900	1,629.806
27	ENERGY MIN ADJ	0.000	0.000	3.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3.000
28	ADJUSTED MWH	69,758.600	75,194.120	74,958.600	75,391.120	75,711.120	72,435.600	69,203.120	62,103.600	70,458.120	69,495.400	64,008.200	68,320.400	847,038.000
29														
30	TRICO													
31	MW	85.694	125.853	164.497	149.759	155.557	140.957	116.234	91.507	90.195	85.104	80.967	72.636	1,359.160
32	MWH	43,348.839	49,883.272	69,143.826	72,230.849	72,594.073	62,002.723	50,728.275	42,934.549	49,950.664	48,018.911	41,759.997	43,690.558	646,286.536
33														
34														
35														
36	FULL REQUIREMENTS													
37	MW	116.232	170.892	222.016	205.829	209.111	188.264	152.094	118.123	123.997	117.089	110.756	102.911	1,837.314
38	MWH	59,862.567	68,524.522	95,414.210	98,433.747	98,292.310	82,414.706	67,586.186	58,857.839	68,925.608	65,506.519	56,827.739	61,399.766	882,045.719
39											0.000		0.000	
40	PARTIAL REQUIREMENTS													
41	MW	263.322	302.008	327.805	320.588	318.436	313.638	279.673	227.283	260.650	256.295	254.933	228.574	3,353.205
42	MWH	147,565.800	157,363.360	159,624.430	167,978.790	168,035.360	155,569.800	142,889.360	122,111.800	134,270.360	129,366.000	116,881.000	120,762.000	1,722,418.060
43														
44														
45														
46	TOTAL CLASS A													
47	MW	379.554	472.900	549.821	526.417	527.547	501.902	431.767	345.406	384.647	373.384	365.689	331.485	5,190.519
48	MWH	207,428.367	225,887.882	255,038.640	266,412.537	266,327.670	237,984.506	210,475.546	180,969.639	203,195.968	194,872.519	173,708.739	182,161.766	2,604,463.779

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED BILLING DETERMINANTS

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	ANZA													
2	KW	5,712	7,488	10,608	10,404	9,948	9,684	6,852	5,388	8,860	8,093	7,071	6,304	96,412
3	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
4	KWH - BASE RESOURCES	2,852,721	3,837,518	3,498,387	4,179,337	4,064,489	3,742,041	3,622,972	3,624,544	4,588,670	3,971,349	3,861,740	2,571,184	44,414,952
5	KWH - OTHER EXISTING RESOURCES	881,235	136,762	1,049,481	1,087,043	898,335	525,912	238,616	58,340	94,134	155,241	101,281	1,476,031	6,702,411
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	124,210	41,835	0	0	0	0	0	0	166,045
7														
8	DUNCAN													
9	KW	3,860	6,040	6,960	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
10	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
11	KWH - BASE RESOURCES	1,531,549	2,339,466	2,479,519	2,349,355	2,361,719	1,997,532	1,800,946	1,875,660	2,246,044	2,142,874	1,835,257	1,260,715	24,220,635
12	KWH - OTHER EXISTING RESOURCES	473,111	83,374	743,831	611,065	521,988	280,736	118,614	30,190	46,076	83,766	48,133	723,735	3,764,620
13	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	72,174	22,332	0	0	0	0	0	0	94,506
14														
15	GRAHAM													
16	KW	20,966	31,511	39,951	39,726	36,986	32,263	24,988	18,448	20,642	19,992	18,818	20,271	324,562
17	KWH - TOTAL	10,775,112	12,244,130	18,499,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
18	KWH - BASE RESOURCES	8,232,123	11,822,788	14,230,236	14,265,620	14,106,426	11,983,452	10,392,305	10,170,848	11,758,796	10,715,505	8,985,666	7,418,708	134,082,474
19	KWH - OTHER EXISTING RESOURCES	2,542,989	421,342	4,268,930	3,710,478	3,117,807	1,684,170	684,458	163,708	241,224	418,873	235,665	4,258,835	21,748,479
20	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	431,089	133,972	0	0	0	0	0	0	565,062
21														
22	MOHAVE													
23	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
24	KWH - TOTAL	77,807,200	82,169,240	84,665,830	92,587,670	92,324,240	83,134,200	73,686,240	60,008,200	63,812,240	59,870,600	52,872,800	52,441,600	875,380,060
25	KWH - BASE RESOURCES	50,755,139	78,652,286	76,386,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
26	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,679,515
27	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
28														
29	SULPHUR													
30	KW	131,134	137,934	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	138,700	128,900	1,629,806
31	KWH - TOTAL	69,758,600	75,194,120	74,958,600	75,391,120	75,711,120	72,435,600	69,203,120	62,103,600	70,458,120	69,495,400	64,008,200	68,320,400	847,038,000
32	KWH - BASE RESOURCES	45,109,060	71,215,789	67,765,404	69,476,926	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	38,296,091	738,282,902
33	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
34	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
35														
36	TRICO													
37	KW	85,906	125,972	164,592	149,858	155,646	141,128	116,545	91,700	90,417	85,278	81,248	73,021	1,361,311
38	KWH - TOTAL	43,348,839	49,883,272	69,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
39	KWH - BASE RESOURCES	33,118,261	48,166,700	53,187,964	57,321,553	58,001,937	53,834,841	47,593,662	42,254,430	48,946,556	46,212,451	40,692,756	27,756,481	557,087,594
40	KWH - OTHER EXISTING RESOURCES	10,230,578	1,716,572	15,955,862	14,909,296	12,819,609	7,566,021	3,134,613	680,119	1,004,108	1,806,460	1,067,241	15,934,077	86,824,555
41	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	1,772,527	601,861	0	0	0	0	0	0	2,374,388
42														
43														
44														
45	FULL REQUIREMENTS													
46	KW	116,444	171,011	222,111	205,928	209,200	188,435	152,405	118,316	124,219	117,263	111,037	103,096	1,839,465
47	KWH - TOTAL	59,862,567	68,524,522	95,414,210	98,433,747	98,292,310	82,414,706	67,586,186	58,857,839	68,925,608	65,506,519	56,827,739	61,399,766	882,045,719
48	KWH - BASE RESOURCES	45,734,653	66,166,471	73,396,106	78,115,865	78,534,571	71,557,867	63,409,885	57,925,482	67,540,066	63,042,179	55,375,419	39,007,088	759,805,654
49	KWH - OTHER EXISTING RESOURCES	14,127,914	2,358,051	22,018,104	20,317,882	17,357,739	10,056,839	4,176,301	932,357	1,385,542	2,464,340	1,452,320	22,392,678	119,040,065
50	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,400,000	800,000	0	0	0	0	0	0	3,200,000
51														
52	PARTIAL REQUIREMENTS													
53	KW	263,322	302,008	327,805	320,588	318,436	313,638	279,673	227,283	260,650	256,295	254,933	228,574	3,353,205
54	KWH - TOTAL	147,565,800	157,363,360	159,624,430	167,978,790	168,035,360	155,569,800	142,889,360	122,111,800	134,270,360	129,366,000	116,881,000	120,762,000	1,722,418,060
55	KWH - BASE RESOURCES	95,864,199	149,868,075	144,151,772	150,173,830	151,454,731	145,316,341	132,669,206	117,258,604	127,316,180	121,117,860	109,939,195	77,853,453	1,522,983,447
56	KWH - OTHER EXISTING RESOURCES	51,701,601	7,495,285	15,472,658	17,804,960	16,580,629	10,253,459	10,220,154	4,853,196	6,954,180	8,248,140	6,941,805	42,908,547	199,434,613
57	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
58														
59	TOTAL CLASS A													
60	KW	379,766	473,019	549,916	526,516	527,636	502,073	432,078	345,599	384,869	373,558	365,970	331,670	5,192,670
61	KWH - TOTAL	207,428,367	225,887,882	255,038,640	266,412,537	266,327,670	237,984,506	210,475,546	180,969,639	203,195,968	194,872,519	173,708,739	182,161,766	2,604,463,779
62	KWH - BASE RESOURCES	141,598,852	216,034,546	217,547,878	228,289,695	229,989,302	216,874,208	196,079,091	175,184,087	194,856,246	184,160,039	165,314,615	116,860,542	2,282,789,101
63	KWH - OTHER EXISTING RESOURCES	65,829,515	9,853,336	37,490,762	38,122,842	33,938,368	20,310,298	14,396,455	5,785,552	8,339,722	10,712,480	8,394,124	65,301,224	318,474,678
64	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,400,000	800,000	0	0	0	0	0	0	3,200,000

Arizona Electric Power Cooperative, Inc.

ANZA ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	6,468	6,132	9,936	11,832	10,716	9,036	5,592	6,564	9,156	7,440	7,596	6,408	96,876
3	kW - Current Year	5,712	7,488	10,608	10,404	9,948	9,684	6,852	5,388	8,860	8,093	7,071	6,304	96,412
4	kW - 12 Month Average	8,010	8,123	8,179	8,060	7,996	8,050	8,155	8,057	8,032	8,087	8,043	8,034	96,826
5	ARM Load Ratio Share	5.34%	5.35%	5.34%	5.30%	5.23%	5.25%	5.31%	5.24%	5.23%	5.27%	5.26%	5.24%	5.28%
6	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
7	KWH - BASE RESOURCES	2,852,721	3,837,518	3,498,387	4,179,337	4,064,489	3,742,041	3,622,972	3,624,544	4,588,670	3,971,349	3,861,740	2,571,184	44,414,952
8	KWH - OTHER EXISTING RESOURCES	881,235	136,762	1,049,481	1,087,043	898,335	525,912	238,616	58,340	94,134	155,241	101,281	1,476,031	6,702,411
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	124,210	41,835	0	0	0	0	0	0	166,045
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$85,566	$112,170	$158,908	$155,852	$149,021	$145,066	$102,643	$80,712	$132,723	$121,233	$105,924	$94,434	$1,444,252
19	Base Energy Charge Revenue	77,405	82,387	94,277	109,172	105,454	89,342	80,051	76,346	97,075	85,544	82,153	83,899	1,063,105
20	Total Present Base Rate Revenue	$162,971	$194,557	$253,185	$265,024	$254,475	$234,408	$182,694	$157,058	$229,797	$206,777	$188,077	$178,333	$2,507,357
21	FPPCA	47,496	50,553	67,127	77,732	75,085	63,612	103,259	98,480	125,218	110,345	105,971	108,223	1,033,100
22	Total Present Revenue	$210,467	$245,110	$320,312	$342,756	$329,560	$298,021	$285,953	$255,539	$355,016	$317,122	$294,048	$286,555	$3,540,457
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	
26	O&M Demand Charge	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	
27	Base Resource Energy Charge	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	
28	Other Existing Resources Energy Charge	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
29	Additional ARM Resources	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$49,677	$49,853	$49,684	$49,362	$48,743	$48,925	$49,424	$48,754	$48,719	$49,107	$48,973	$48,802	$590,022
34	O&M Demand Charge Revenue	62,875	63,098	62,885	62,477	61,093	61,923	62,555	61,708	61,662	62,154	61,984	61,768	746,781
35	Base Resource Energy Revenue	92,270	124,123	113,154	135,179	131,465	121,035	117,184	117,235	148,419	128,452	124,907	83,164	1,436,587
36	Other Existing Resources Energy Revenue	59,449	9,226	70,799	73,333	60,603	35,479	16,097	3,936	6,350	10,473	6,833	99,575	452,152
37	Additional ARM Resources	0	0	0	0	8,379	2,822	0	0	0	0	0	0	11,202
38	Total Proposed Base Rate Revenue	$264,271	$246,301	$296,522	$320,352	$310,882	$270,184	$245,260	$231,632	$265,150	$250,185	$242,695	$293,309	$3,236,743
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$264,271	$246,301	$296,522	$320,352	$310,882	$270,184	$245,260	$231,632	$265,150	$250,185	$242,695	$293,309	$3,236,743
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$26,986	$781	($46,339)	($44,013)	($38,586)	($34,218)	$9,336	$29,750	($22,342)	($9,972)	$5,033	$16,136	($107,449)
44	Change in Base Energy Charge Revenue	74,314	50,963	89,676	99,340	94,992	69,994	53,230	44,824	57,695	53,381	49,686	98,840	836,836
45	Change in Base Rate Revenue	$101,300	$51,744	$43,337	$55,328	$56,406	$35,776	$62,566	$74,574	$35,353	$43,408	$54,618	$114,976	$729,386
46	Change in FPPCA Revenue	(47,496)	(50,553)	(67,127)	(77,732)	(75,085)	(63,612)	(103,259)	(98,480)	(125,218)	(110,345)	(105,971)	(108,223)	(1,033,100)
47	Change in Total Revenue	$53,804	$1,191	($23,789)	($22,404)	($18,678)	($27,837)	($40,693)	($23,906)	($89,865)	($66,937)	($51,353)	$6,754	($303,714)
48	Percentage Change in Base Rate Revenue	62.16%	26.60%	17.12%	20.88%	22.17%	15.26%	34.25%	47.48%	15.38%	20.99%	29.04%	64.47%	29.09%
49	Percentage Change in Total Revenue	25.56%	0.49%	-7.43%	-6.54%	-5.67%	-9.34%	-14.23%	-9.36%	-25.31%	-21.11%	-17.46%	2.36%	-8.58%

Arizona Electric Power Cooperative, Inc.

DUNCAN ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	3,100	5,640	6,660	6,020	6,520	3,720	4,520	3,320	4,520	4,320	4,180	3,260	55,780
3	kW - Current Year	3,860	6,040	6,960	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
4	kW - 12 Month Average	4,712	4,745	4,770	4,763	4,772	4,908	4,867	4,822	4,803	4,768	4,745	4,765	57,440
5	ARM Load Ratio Share	3.14%	3.13%	3.11%	3.13%	3.12%	3.20%	3.17%	3.13%	3.13%	3.11%	3.10%	3.11%	3.13%
6	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
7	KWH - BASE RESOURCES	1,531,549	2,339,466	2,479,519	2,349,355	2,361,719	1,997,532	1,800,946	1,875,660	2,246,044	2,142,874	1,835,257	1,260,715	24,220,635
8	KWH - OTHER EXISTING RESOURCES	473,111	83,374	743,831	611,065	521,988	280,736	118,614	30,190	46,076	83,766	48,133	723,735	3,764,620
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	72,174	22,332	0	0	0	0	0	0	94,506
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$57,823	$90,479	$104,261	$88,981	$99,168	$80,293	$60,220	$41,644	$64,414	$58,422	$58,422	$52,430	$856,556
19	Base Energy Charge Revenue	41,557	50,225	66,820	61,370	61,275	47,691	39,792	39,508	47,516	46,158	39,043	41,138	582,093
20	Total Present Base Rate Revenue	$99,379	$140,705	$171,081	$150,351	$160,443	$127,984	$100,012	$81,153	$111,930	$104,580	$97,465	$93,568	$1,438,650
21	FPPCA	25,499	30,819	47,577	43,696	43,629	33,957	51,329	50,962	61,291	59,540	50,362	53,064	551,725
22	Total Present Revenue	$124,879	$171,523	$218,657	$194,047	$204,072	$161,941	$151,341	$132,116	$173,221	$164,121	$147,827	$146,632	$1,990,375
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	
26	O&M Demand Charge	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	
27	Base Resource Energy Charge	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	
28	Other Existing Resources Energy Charge	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
29	Additional ARM Resources	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$29,221	$29,121	$28,976	$29,172	$29,087	$29,831	$29,495	$29,177	$29,134	$28,956	$28,892	$28,944	$350,005
34	O&M Demand Charge Revenue	36,984	36,858	36,674	36,923	36,815	37,757	37,331	36,929	36,874	36,649	36,568	36,633	442,995
35	Base Resource Energy Revenue	49,537	75,669	80,199	75,989	76,389	64,610	58,251	60,668	72,648	69,311	59,361	40,777	783,409
36	Other Existing Resources Energy Revenue	31,917	5,625	50,180	41,223	35,214	18,939	8,002	2,037	3,108	5,651	3,247	48,824	253,965
37	Additional ARM Resources	0	0	0	0	4,869	1,507	0	0	0	0	0	0	6,375
38	Total Proposed Base Rate Revenue	$147,659	$147,274	$196,029	$183,308	$182,375	$152,642	$133,078	$128,810	$141,764	$140,566	$128,067	$155,178	$1,836,750
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$147,659	$147,274	$196,029	$183,308	$182,375	$152,642	$133,078	$128,810	$141,764	$140,566	$128,067	$155,178	$1,836,750
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$8,383	($24,499)	($38,611)	($22,886)	($33,265)	($12,705)	$6,606	$24,461	$1,594	$7,183	$7,037	$13,147	($63,556)
44	Change in Base Energy Charge Revenue	39,897	31,068	63,559	55,843	55,196	37,363	26,460	23,196	28,240	28,803	23,565	48,464	461,656
45	Change in Base Rate Revenue	$48,280	$6,569	$24,948	$32,957	$21,932	$24,658	$33,066	$47,657	$29,834	$35,986	$30,602	$61,611	$398,100
46	Change in FPPCA Revenue	(25,499)	(30,819)	(47,577)	(43,696)	(43,629)	(33,957)	(51,329)	(50,962)	(61,291)	(59,540)	(50,362)	(53,064)	(551,725)
47	Change in Total Revenue	$22,781	($24,250)	($22,628)	($10,739)	($21,697)	($9,299)	($18,263)	($3,305)	($31,457)	($23,554)	($19,760)	$8,546	($153,625)
48	Percentage Change in Base Rate Revenue	48.58%	4.67%	14.58%	21.92%	13.67%	19.27%	33.06%	58.73%	26.65%	34.41%	31.40%	65.85%	27.67%
49	Percentage Change in Total Revenue	18.24%	-14.14%	-10.35%	-5.53%	-10.63%	-5.74%	-12.07%	-2.50%	-18.16%	-14.35%	-13.37%	5.83%	-7.72%

Arizona Electric Power Cooperative, Inc.

GRAHAM ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	21,235	29,349	40,099	39,125	36,733	30,341	27,052	18,498	21,918	20,119	19,731	19,458	323,658
3	kW - Current Year	20,966	31,511	39,951	39,726	36,986	32,263	24,988	18,448	20,642	19,992	18,818	20,271	324,562
4	kW - 12 Month Average	26,949	27,129	27,117	27,167	27,188	27,348	27,176	27,172	27,066	27,055	26,979	27,047	325,394
5	ARM Load Ratio Share	17.95%	17.88%	17.69%	17.87%	17.80%	17.85%	17.69%	17.66%	17.63%	17.64%	17.64%	17.64%	17.75%
6	KWH - TOTAL	10,775,112	12,244,130	18,499,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
7	KWH - BASE RESOURCES	8,232,123	11,822,788	14,230,236	14,265,620	14,106,426	11,983,452	10,392,305	10,170,848	11,758,796	10,715,505	8,985,666	7,418,708	134,082,474
8	KWH - OTHER EXISTING RESOURCES	2,542,989	421,342	4,268,930	3,710,478	3,117,807	1,684,170	684,458	163,708	241,224	418,873	235,665	4,258,835	21,748,479
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	431,089	133,972	0	0	0	0	0	0	565,062
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$314,071	$472,035	$598,466	$595,095	$554,050	$483,300	$374,320	$276,351	$309,217	$299,480	$281,894	$303,660	$4,861,939
19	Base Energy Charge Revenue	223,368	253,821	383,488	372,645	365,995	286,107	229,621	214,235	248,760	230,816	191,158	242,075	3,242,089
20	Total Present Base Rate Revenue	$537,439	$725,856	$981,954	$967,740	$920,045	$769,407	$603,942	$490,586	$557,978	$530,296	$473,052	$545,735	$8,104,028
21	FPPCA	137,059	155,745	273,048	265,327	260,593	203,712	296,193	276,346	320,881	297,733	246,578	312,257	3,045,472
22	Total Present Revenue	$674,498	$881,601	$1,255,001	$1,233,067	$1,180,638	$973,118	$900,134	$766,932	$878,858	$828,029	$719,630	$857,993	$11,149,500
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	
26	O&M Demand Charge	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	
27	Base Resource Energy Charge	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	
28	Other Existing Resources Energy Charge	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
29	Additional ARM Resources	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$167,134	$166,499	$164,725	$166,380	$165,736	$166,212	$164,703	$164,423	$164,162	$164,293	$164,271	$164,288	$1,982,825
34	O&M Demand Charge Revenue	211,538	210,736	208,490	210,585	209,768	210,372	208,462	208,108	207,777	207,943	207,915	207,936	2,509,628
35	Base Resource Energy Revenue	266,265	382,404	460,272	461,417	456,268	387,601	336,136	328,973	380,335	346,590	290,638	239,956	4,336,855
36	Other Existing Resources Energy Revenue	171,553	28,424	287,987	250,313	210,331	113,616	46,174	11,044	16,273	28,258	15,898	287,305	1,467,175
37	Additional ARM Resources	0	0	0	0	29,082	9,038	0	0	0	0	0	0	38,120
38	Total Proposed Base Rate Revenue	$816,490	$788,064	$1,121,473	$1,088,695	$1,071,183	$886,838	$755,475	$712,548	$768,547	$747,083	$678,723	$899,485	$10,334,603
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$816,490	$788,064	$1,121,473	$1,088,695	$1,071,183	$886,838	$755,475	$712,548	$768,547	$747,083	$678,723	$899,485	$10,334,603
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$64,601	($94,800)	($225,251)	($218,130)	($178,548)	($106,716)	($1,155)	$96,180	$62,722	$72,756	$90,293	$68,564	($369,485)
44	Change in Base Energy Charge Revenue	214,450	157,008	364,771	339,085	329,685	224,148	152,689	125,761	147,847	144,032	115,379	285,186	2,600,061
45	Change in Base Rate Revenue	$279,051	$62,208	$139,520	$120,955	$151,138	$117,432	$151,534	$221,961	$210,569	$216,787	$205,671	$353,750	$2,230,575
46	Change in FPPCA Revenue	(137,059)	(155,745)	(273,048)	(265,327)	(260,593)	(203,712)	(296,193)	(276,346)	(320,881)	(297,733)	(246,578)	(312,257)	(3,045,472)
47	Change in Total Revenue	$141,992	($93,537)	($133,528)	($144,372)	($109,455)	($86,280)	($144,659)	($54,385)	($110,311)	($80,946)	($40,907)	$41,492	($814,897)
48	Percentage Change in Base Rate Revenue	51.92%	8.57%	14.21%	12.50%	16.43%	15.26%	25.09%	45.24%	37.74%	40.88%	43.48%	64.82%	27.52%
49	Percentage Change in Total Revenue	21.05%	-10.61%	-10.64%	-11.71%	-9.27%	-8.87%	-16.07%	-7.09%	-12.55%	-9.78%	-5.68%	4.84%	-7.31%

Arizona Electric Power Cooperative, Inc.

MOHAVE ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.011050	$0.011050	$0.013050	$0.013050	$0.013050	$0.013050	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$855,113	$855,113	$855,113	$855,113	$855,113	$841,539	$855,113	$855,113	$855,113	$841,248	$855,113	$841,405	$10,220,208
7														
8	**PRESENT REVENUES**													
9	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
10	KWH - BASE RESOURCES	50,755,139	78,652,286	76,386,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
11	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,679,515
12	Demand Revenue	$1,814,798	$2,046,290	$2,167,510	$2,168,113	$2,167,010	$2,131,670	$1,926,246	$1,646,083	$1,719,895	$1,680,468	$1,698,967	$1,565,038	$22,732,087
13	Base Energy Charge Revenue	1,612,943	1,703,368	1,755,123	1,919,342	1,913,881	1,723,372	1,527,516	1,243,970	1,322,828	1,241,118	1,096,053	1,087,114	18,146,629
14	Total Present Base Rate Revenue	$3,427,741	$3,749,659	$3,922,633	$4,087,455	$4,080,891	$3,855,042	$3,453,762	$2,890,053	$3,042,723	$2,921,585	$2,795,020	$2,652,152	$40,878,716
15	FPPCA	859,770	907,970	1,104,889	1,208,269	1,204,831	1,084,901	1,879,736	1,530,809	1,627,850	1,527,299	1,348,785	1,337,785	15,622,895
16	Total Present Revenue	$4,287,511	$4,657,629	$5,027,522	$5,295,725	$5,285,722	$4,939,943	$5,333,498	$4,420,862	$4,670,573	$4,448,884	$4,143,805	$3,989,937	$56,501,611
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	
20	O&M Demand Charge	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	
21	Base Resource Energy Charge	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	
22	Other Existing Resources Energy Charge	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$9,179,703
27	O&M Demand Charge Revenue	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	15,298,589
28	Base Resource Energy Revenue	1,631,645	2,528,466	2,455,622	2,594,195	2,612,518	2,472,658	2,217,326	1,887,770	2,008,670	1,871,542	1,673,996	1,271,666	25,226,075
29	Other Existing Resources Energy Revenue	1,860,829	241,921	569,519	817,930	760,603	427,710	324,157	88,450	91,425	113,708	55,049	886,267	6,237,567
30	Total Proposed Base Rate Revenue	$5,532,332	$4,810,244	$5,064,999	$5,451,982	$5,412,978	$4,940,226	$4,581,341	$4,016,078	$4,139,952	$4,025,108	$3,768,902	$4,197,791	$55,941,934
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$5,532,332	$4,810,244	$5,064,999	$5,451,982	$5,412,978	$4,940,226	$4,581,341	$4,016,078	$4,139,952	$4,025,108	$3,768,902	$4,197,791	$55,941,934
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$225,060	($6,433)	($127,653)	($128,255)	($127,152)	($91,812)	$113,612	$393,775	$319,962	$359,390	$340,891	$474,820	$1,746,204
36	Change in Energy Charge Revenue	1,879,531	1,067,018	1,270,019	1,492,782	1,459,239	1,176,997	1,013,968	732,250	777,267	744,133	632,991	1,070,819	13,317,014
37	Change in Base Rate Revenue	$2,104,591	$1,060,585	$1,142,366	$1,364,527	$1,332,087	$1,085,184	$1,127,579	$1,126,025	$1,097,230	$1,103,523	$973,882	$1,545,639	$15,063,218
38	Change in FPPCA Revenue	(859,770)	(907,970)	(1,104,889)	(1,208,269)	(1,204,831)	(1,084,901)	(1,879,736)	(1,530,809)	(1,627,850)	(1,527,299)	(1,348,785)	(1,337,785)	(15,622,895)
39	Change in Total Revenue	$1,244,821	$152,615	$37,477	$156,258	$127,256	$283	($752,157)	($404,784)	($530,621)	($423,776)	($374,903)	$207,854	($559,677)
40	Percentage Change in Base Rate Revenue	61.40%	28.28%	29.12%	33.38%	32.64%	28.15%	32.65%	38.96%	36.06%	37.77%	34.84%	58.28%	36.85%
41	Percentage Change in Total Revenue	29.03%	3.28%	0.75%	2.95%	2.41%	0.01%	-14.10%	-9.16%	-11.36%	-9.53%	-9.05%	5.21%	-0.99%

Arizona Electric Power Cooperative, Inc.

SULPHUR SPRINGS ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.011050	$0.011050	$0.013050	$0.013050	$0.013050	$0.013050	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$9,089,148
7														
8	**PRESENT REVENUES**													
9	KW	131,134	137,934	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	138,700	128,900	1,629,806
10	KWH - BASE RESOURCES	45,109,060	71,215,789	67,765,404	69,476,926	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	38,296,091	738,282,902
11	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
12	Demand Revenue	$1,709,462	$1,758,830	$1,824,896	$1,771,898	$1,757,378	$1,744,310	$1,716,722	$1,616,534	$1,784,966	$1,778,911	$1,764,391	$1,693,243	$20,921,540
13	Base Energy Charge Revenue	1,446,096	1,558,774	1,553,892	1,562,858	1,569,492	1,501,590	1,434,581	1,287,408	1,460,597	1,440,640	1,326,890	1,416,282	17,559,098
14	Total Present Base Rate Revenue	$3,155,558	$3,317,604	$3,378,788	$3,334,756	$3,326,869	$3,245,900	$3,151,303	$2,903,941	$3,245,563	$3,219,551	$3,091,281	$3,109,525	$38,480,637
15	FPPCA	770,833	830,895	978,210	983,854	988,030	945,285	1,765,372	1,584,263	1,797,387	1,772,828	1,632,849	1,742,853	15,792,657
16	Total Present Revenue	$3,926,390	$4,148,499	$4,356,997	$4,318,610	$4,314,899	$4,191,184	$4,916,674	$4,488,204	$5,042,949	$4,992,378	$4,724,130	$4,852,378	$54,273,295
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	
20	O&M Demand Charge	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	
21	Base Resource Energy Charge	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	
22	Other Existing Resources Energy Charge	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$8,128,396
27	O&M Demand Charge Revenue	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	13,546,516
28	Base Resource Energy Revenue	1,456,357	2,299,219	2,187,822	2,243,079	2,266,032	2,208,312	2,056,423	1,889,857	2,093,151	2,030,752	1,868,240	1,236,399	23,835,642
29	Other Existing Resources Energy Revenue	1,645,489	265,575	480,184	394,804	368,707	269,395	367,667	238,139	375,504	440,258	409,980	2,004,284	7,259,986
30	Total Proposed Base Rate Revenue	$4,908,089	$4,371,037	$4,474,250	$4,444,126	$4,440,982	$4,283,950	$4,230,332	$3,934,239	$4,274,897	$4,277,252	$4,084,462	$5,046,925	$52,770,540
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$4,908,089	$4,371,037	$4,474,250	$4,444,126	$4,440,982	$4,283,950	$4,230,332	$3,934,239	$4,274,897	$4,277,252	$4,084,462	$5,046,925	$52,770,540
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$96,781	$47,413	($18,653)	$34,345	$48,865	$61,933	$89,521	$189,709	$21,277	$27,332	$41,852	$113,000	$753,372
36	Change in Energy Charge Revenue	1,655,750	1,006,020	1,114,115	1,075,026	1,065,248	976,117	989,509	840,589	1,008,058	1,030,370	951,329	1,824,400	13,536,530
37	Change in Base Rate Revenue	$1,752,531	$1,053,433	$1,095,462	$1,109,370	$1,114,112	$1,038,050	$1,079,030	$1,030,298	$1,029,335	$1,057,701	$993,181	$1,937,400	$14,289,903
38	Change in FPPCA Revenue	(770,833)	(830,895)	(978,210)	(983,854)	(988,030)	(945,285)	(1,765,372)	(1,584,263)	(1,797,387)	(1,772,828)	(1,632,849)	(1,742,853)	(15,792,657)
39	Change in Total Revenue	$981,698	$222,538	$117,252	$125,516	$126,082	$92,765	($686,342)	($553,965)	($768,052)	($715,126)	($639,668)	$194,547	($1,502,755)
40	Percentage Change in Base Rate Revenu	55.54%	31.75%	32.42%	33.27%	33.49%	31.98%	34.24%	35.48%	31.72%	32.85%	32.13%	62.31%	37.14%
41	Percentage Change in Total Revenue	25.00%	5.36%	2.69%	2.91%	2.92%	2.21%	-13.96%	-12.34%	-15.23%	-14.32%	-13.54%	4.01%	-2.77%

Arizona Electric Power Cooperative, Inc.

TRICO ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	88,830	110,939	146,640	163,888	146,704	139,833	110,067	87,080	92,923	87,572	84,462	69,545	1,328,483
3	kW - Current Year	85,906	125,972	164,592	149,858	155,646	141,128	116,545	91,700	90,417	85,278	81,248	73,021	1,361,311
4	kW - 12 Month Average	110,463	111,716	113,212	112,043	112,788	112,896	113,436	113,821	113,612	113,421	113,153	113,443	1,354,003
5	ARM Load Ratio Share	73.58%	73.64%	73.86%	73.70%	73.84%	73.69%	73.84%	73.97%	74.01%	73.97%	73.99%	74.01%	73.84%
6	KWH - TOTAL	43,348,839	49,883,272	69,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
7	KWH - BASE RESOURCES	33,118,261	48,166,700	53,187,964	57,321,553	58,001,937	53,834,841	47,593,662	42,254,430	48,946,556	46,212,451	40,692,756	27,756,481	557,087,594
8	KWH - OTHER EXISTING RESOURCES	10,230,578	1,716,572	15,955,862	14,909,296	12,819,609	7,566,021	3,134,613	660,119	1,004,108	1,806,460	1,067,241	15,934,077	86,824,555
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	1,772,527	601,861	0	0	0	0	0	0	2,374,388
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$1,286,872	$1,887,061	$2,465,588	$2,244,873	$2,331,577	$2,114,097	$1,745,844	$1,373,666	$1,354,447	$1,277,464	$1,217,095	$1,093,855	$20,392,439
19	Base Energy Charge Revenue	898,621	1,034,080	1,433,352	1,497,345	1,504,875	1,285,316	1,051,597	890,033	1,035,477	995,432	865,685	905,705	13,397,520
20	Total Present Base Rate Revenue	$2,185,493	$2,921,141	$3,898,940	$3,742,218	$3,836,452	$3,399,414	$2,797,441	$2,263,699	$2,389,924	$2,272,896	$2,082,780	$1,999,560	$33,789,959
21	FPPCA	551,397	634,515	1,020,563	1,066,127	1,071,489	915,160	1,356,474	1,148,070	1,335,681	1,284,026	1,116,662	1,168,286	12,668,450
22	Total Present Revenue	$2,736,891	$3,555,656	$4,919,503	$4,808,346	$4,907,941	$4,314,574	$4,153,915	$3,411,769	$3,725,605	$3,556,922	$3,199,442	$3,167,845	$46,458,408
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	
26	O&M Demand Charge	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	
27	Base Resource Energy Charge	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	
28	Other Existing Resources Energy Charge	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
29	Additional ARM Resources	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$685,074	$685,631	$687,720	$686,190	$687,540	$686,137	$687,483	$688,750	$689,091	$688,749	$688,970	$689,072	$8,250,406
34	O&M Demand Charge Revenue	867,086	867,792	870,435	868,499	870,208	868,432	870,136	871,740	872,171	871,738	872,017	872,147	10,442,402
35	Base Resource Energy Revenue	1,071,200	1,557,937	1,720,348	1,854,047	1,876,054	1,741,271	1,539,402	1,366,706	1,583,161	1,494,727	1,316,194	897,775	18,018,821
36	Other Existing Resources Energy Revenue	690,166	115,802	1,076,399	1,005,797	864,824	510,412	211,464	45,882	67,738	121,866	71,997	1,074,930	5,857,276
37	Additional ARM Resources	0	0	0	0	119,577	40,602	0	0	0	0	0	0	160,179
38	Total Proposed Base Rate Revenue	$3,313,525	$3,227,161	$4,354,902	$4,414,533	$4,418,203	$3,846,854	$3,308,485	$2,973,078	$3,212,160	$3,177,080	$2,949,178	$3,533,922	$42,729,083
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$3,313,525	$3,227,161	$4,354,902	$4,414,533	$4,418,203	$3,846,854	$3,308,485	$2,973,078	$3,212,160	$3,177,080	$2,949,178	$3,533,922	$42,729,083
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$265,288	($333,638)	($907,433)	($690,184)	($773,829)	($559,528)	($188,225)	$186,824	$206,815	$283,023	$343,892	$467,364	($1,699,631)
44	Change in Base Energy Charge Revenue	862,744	639,658	1,363,396	1,362,499	1,355,580	1,006,968	699,269	522,554	615,422	621,161	522,507	1,066,999	10,638,756
45	Change in Base Rate Revenue	$1,128,032	$306,020	$455,962	$672,315	$581,751	$447,440	$511,044	$709,379	$822,236	$904,184	$866,398	$1,534,363	$8,939,125
46	Change in FPPCA Revenue	(551,397)	(634,515)	(1,020,563)	(1,066,127)	(1,071,489)	(915,160)	(1,356,474)	(1,148,070)	(1,335,681)	(1,284,026)	(1,116,662)	(1,168,286)	(12,668,450)
47	Change in Total Revenue	$576,635	($328,495)	($564,601)	($393,812)	($489,738)	($467,720)	($845,430)	($438,691)	($513,445)	($379,842)	($250,264)	$366,077	($3,729,325)
48	Percentage Change in Base Rate Revenue	51.61%	10.48%	11.69%	17.97%	15.16%	13.16%	18.27%	31.34%	34.40%	39.78%	41.60%	76.74%	26.45%
49	Percentage Change in Total Revenue	21.07%	-9.24%	-11.48%	-8.19%	-9.98%	-10.84%	-20.35%	-12.86%	-13.78%	-10.68%	-7.82%	11.56%	-8.03%

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT REVENUES**													
2	FULL REQUIREMENTS													
3	Demand Revenue	$1,744,331	$2,561,745	$3,327,223	$3,084,801	$3,133,816	$2,822,756	$2,283,027	$1,772,374	$1,860,601	$1,756,600	$1,663,334	$1,544,378	$27,555,186
4	Base Energy Revenue	1,240,951	1,420,513	1,977,937	2,040,532	2,037,600	1,708,457	1,401,062	1,220,123	1,428,828	1,357,950	1,178,039	1,272,817	18,284,808
5	Total Present Base Rate Revenue	$2,985,282	$3,982,258	$5,305,159	$5,125,333	$5,171,416	$4,531,213	$3,684,089	$2,992,497	$3,289,628	$3,114,550	$2,841,373	$2,817,195	$45,839,993
6	FPPCA	761,452	871,632	1,408,314	1,452,882	1,450,794	1,216,441	1,807,255	1,573,859	1,843,071	1,751,644	1,519,574	1,641,830	17,298,747
7	Total Adjusted Present Revenue	$3,746,734	$4,853,890	$6,713,473	$6,578,215	$6,622,210	$5,747,654	$5,491,343	$4,566,355	$5,132,699	$4,866,194	$4,360,947	$4,459,025	$63,138,740
8														
9	PARTIAL REQUIREMENTS													
10	Fixed / O&M Charge Revenue	$3,524,260	$3,805,120	$3,992,406	$3,940,011	$3,924,387	$3,875,980	$3,642,968	$3,262,617	$3,504,861	$3,459,379	$3,463,358	$3,258,281	$43,653,627
11	Base Energy Revenue	3,059,039	3,262,142	3,309,014	3,482,200	3,483,373	3,224,962	2,962,096	2,531,378	2,783,425	2,681,757	2,422,943	2,503,396	35,705,726
12	Total Present Base Rate Revenue	$6,583,299	$7,067,263	$7,301,421	$7,422,211	$7,407,760	$7,100,942	$6,605,064	$5,793,994	$6,288,286	$6,141,136	$5,886,301	$5,761,677	$79,359,353
13	FPPCA	1,630,602	1,738,865	2,083,099	2,192,123	2,192,861	2,030,186	3,645,108	3,115,072	3,425,237	3,300,127	2,981,634	3,080,639	31,415,553
14	Total Adjusted Present Revenue	$8,213,901	$8,806,128	$9,384,520	$9,614,334	$9,600,622	$9,131,128	$10,250,172	$8,909,066	$9,713,522	$9,441,262	$8,867,935	$8,842,316	$110,774,906
15														
16	TOTAL CLASS A													
17	Demand Revenue	$5,268,591	$6,366,865	$7,319,629	$7,024,812	$7,058,203	$6,698,736	$5,925,995	$5,034,990	$5,365,662	$5,215,978	$5,126,692	$4,802,659	$71,208,813
18	Base Energy Revenue	4,299,990	4,682,656	5,286,951	5,522,732	5,520,973	4,933,419	4,363,158	3,751,501	4,212,252	4,039,707	3,600,982	3,776,213	53,990,534
19	Total Present Base Rate Revenue	$9,568,581	$11,049,521	$12,606,580	$12,547,544	$12,579,176	$11,632,155	$10,289,153	$8,786,491	$9,577,914	$9,255,686	$8,727,674	$8,578,872	$125,199,347
20	FPPCA	2,392,054	2,610,497	3,491,413	3,645,005	3,643,656	3,246,627	5,452,362	4,688,931	5,268,308	5,051,771	4,501,208	4,722,468	48,714,300
21	Total Adjusted Present Revenue	$11,960,635	$13,660,018	$16,097,993	$16,192,550	$16,222,832	$14,878,782	$15,741,515	$13,475,422	$14,846,222	$14,307,457	$13,228,882	$13,301,341	$173,913,646
22														
23	**PROPOSED REVENUES**													
24	FULL REQUIREMENTS													
25	Demand Revenue	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$25,315,064
26	Base Energy Revenue	2,432,357	2,299,210	3,859,338	3,897,299	3,873,054	3,046,930	2,332,710	1,936,479	2,276,032	2,205,326	1,889,075	2,772,305	32,822,116
27	Total Proposed Base Rate Revenue	$4,541,945	$4,408,799	$5,968,927	$6,006,887	$5,982,642	$5,156,519	$4,442,299	$4,046,068	$4,387,621	$4,314,915	$3,998,664	$4,881,894	$58,137,179
28	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total Adjusted Proposed Revenue	$4,541,945	$4,408,799	$5,968,927	$6,006,887	$5,982,642	$5,156,519	$4,442,299	$4,046,068	$4,387,621	$4,314,915	$3,998,664	$4,881,894	$58,137,179
30														
31	PARTIAL REQUIREMENTS													
32	Fixed / O&M Charge Revenue	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$46,153,204
33	Base Energy Revenue	6,594,320	5,335,180	5,693,148	6,050,008	6,007,860	5,378,076	4,965,573	4,104,217	4,568,749	4,456,260	4,007,264	5,398,616	62,559,271
34	Total Proposed Base Rate Revenue	$10,440,420	$9,181,281	$9,539,249	$9,896,108	$9,853,960	$9,224,176	$8,811,674	$7,950,317	$8,414,850	$8,302,360	$7,853,364	$9,244,716	$108,712,474
35	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total Adjusted Proposed Revenue	$10,440,420	$9,181,281	$9,539,249	$9,896,108	$9,853,960	$9,224,176	$8,811,674	$7,950,317	$8,414,850	$8,302,360	$7,853,364	$9,244,716	$108,712,474
37														
38	TOTAL CLASS A													
39	Demand Revenue	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$71,468,267
40	Base Energy Revenue	9,026,677	7,634,390	9,552,486	9,947,307	9,880,913	8,425,006	7,298,283	6,040,696	6,846,781	6,661,586	5,896,339	8,170,921	95,381,386
41	Total Proposed Base Rate Revenue	$14,982,366	$13,590,079	$15,508,175	$15,902,995	$15,836,602	$14,380,695	$13,253,972	$11,996,385	$12,802,470	$12,617,275	$11,852,028	$14,126,610	$166,849,654
42	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Adjusted Proposed Revenue	$14,982,366	$13,590,079	$15,508,175	$15,902,995	$15,836,602	$14,380,695	$13,253,972	$11,996,385	$12,802,470	$12,617,275	$11,852,028	$14,126,610	$166,849,654
44														
45	**PROPOSED REVENUE CHANGES**													
46	FULL REQUIREMENTS													
47	Demand Revenue	$365,258	($452,156)	($1,217,634)	($975,213)	($1,024,227)	($713,168)	($173,438)	$337,215	$248,788	$352,989	$446,254	$565,211	($2,240,122)
48	Base Energy Revenue	1,191,406	878,697	1,881,402	1,856,767	1,835,454	1,338,473	931,649	716,356	849,204	847,376	711,036	1,499,488	14,537,308
49	Change in Base Rate Revenue	$1,556,663	$426,541	$663,767	$881,554	$811,227	$625,306	$758,210	$1,053,571	$1,097,992	$1,200,365	$1,157,291	$2,064,699	$12,297,186
50	FPPCA	(761,452)	(871,632)	(1,408,314)	(1,452,882)	(1,450,794)	(1,216,441)	(1,807,255)	(1,573,859)	(1,843,071)	(1,751,644)	(1,519,574)	(1,641,830)	(17,298,747)
51	Total Revenue Change	$795,211	($445,091)	($744,546)	($571,328)	($639,568)	($591,135)	($1,049,044)	($520,288)	($745,079)	($551,279)	($362,283)	$422,869	($5,001,561)
52	Percent Change in Base Rate Revenue	23.65%	6.04%	9.09%	11.88%	10.95%	8.81%	11.48%	18.18%	17.46%	19.55%	19.66%	35.84%	15.50%
53	Percent Change in Total Revenue	21.22%	-9.17%	-11.09%	-8.69%	-9.66%	-10.28%	-19.10%	-11.39%	-14.52%	-11.33%	-8.31%	9.48%	-7.92%
54														
55	PARTIAL REQUIREMENTS													
56	Fixed / O&M Charge Revenue	$321,841	$40,980	($146,306)	($93,911)	($78,287)	($29,879)	$203,132	$583,484	$341,239	$386,722	$382,743	$587,819	$2,499,577
57	Base Energy Revenue	3,535,281	2,073,038	2,384,134	2,567,808	2,524,487	2,153,114	2,003,477	1,572,839	1,785,325	1,774,503	1,584,321	2,895,219	26,853,544
58	Change in Base Rate Revenue	$3,857,122	$2,114,018	$2,237,828	$2,473,897	$2,446,200	$2,123,234	$2,206,609	$2,156,323	$2,126,564	$2,161,224	$1,967,063	$3,483,039	$29,353,121
59	FPPCA	(1,630,602)	(1,738,865)	(2,083,099)	(2,192,123)	(2,192,861)	(2,030,186)	(3,645,108)	(3,115,072)	(3,425,237)	(3,300,127)	(2,981,634)	(3,080,639)	(31,415,553)
60	Total Revenue Change	$2,226,519	$375,153	$154,729	$281,774	$253,338	$93,049	($1,438,498)	($958,749)	($1,298,673)	($1,138,902)	($1,014,571)	$402,400	($2,062,432)
61	Percent Change in Base Rate Revenue	58.59%	29.91%	30.65%	33.33%	33.02%	29.90%	33.41%	37.22%	33.82%	35.19%	33.42%	60.45%	36.99%
62	Percent Change in Total Revenue	27.11%	4.26%	1.65%	2.93%	2.64%	1.02%	-14.03%	-10.76%	-13.37%	-12.06%	-11.44%	4.55%	-1.86%
63														
64	TOTAL CLASS A													
65	Demand Revenue	$687,098	($411,176)	($1,363,940)	($1,069,123)	($1,102,514)	($743,047)	$29,694	$920,699	$590,027	$739,711	$828,997	$1,153,030	$259,455
66	Base Energy Revenue	4,726,687	2,951,734	4,265,535	4,424,575	4,359,941	3,491,587	2,935,125	2,289,195	2,634,529	2,621,879	2,295,357	4,394,708	41,390,852
67	Percent Change in Base Rate Revenue	$5,413,785	$2,540,559	$2,901,595	$3,355,451	$3,257,428	$2,748,540	$2,964,819	$3,209,894	$3,224,556	$3,361,589	$3,124,354	$5,547,738	$41,650,307
68	FPPCA	(2,392,054)	(2,610,497)	(3,491,413)	(3,645,005)	(3,643,656)	(3,246,627)	(5,452,362)	(4,688,931)	(5,268,308)	(5,051,771)	(4,501,208)	(4,722,468)	(48,714,300)
69	Total Revenue Change	$3,021,731	($69,938)	($589,817)	($289,554)	($386,230)	($498,087)	($2,487,543)	($1,479,037)	($2,043,751)	($1,690,182)	($1,376,854)	$825,269	($7,063,993)
70	Percent Change in Base Rate Revenue	56.56%	22.99%	23.02%	26.74%	25.90%	23.63%	26.81%	36.53%	33.67%	36.32%	35.80%	64.67%	33.27%
71	Percent Change in Total Revenue	25.26%	-0.51%	-3.66%	-1.79%	-2.38%	-3.35%	-15.80%	-10.98%	-13.77%	-11.81%	-10.41%	6.20%	-4.06%

Arizona Electric Power Cooperative, Inc.

ANALYSIS OF REVENUE BY DETAILED CLASS WITH ACTUAL FPPCA - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	AVERAGE COST PER KWH - PRESENT REVENUES													
2	ANZA	$0.05637	$0.06167	$0.07043	$0.06508	$0.06478	$0.06915	$0.07405	$0.06939	$0.07581	$0.07685	$0.07420	$0.07080	$0.06904
3	DUNCAN	$0.06229	$0.07079	$0.06784	$0.06555	$0.06904	$0.07039	$0.07884	$0.06932	$0.07557	$0.07371	$0.07849	$0.07389	$0.07088
4	GRAHAM	$0.06260	$0.07200	$0.06784	$0.06859	$0.06687	$0.07051	$0.08126	$0.07421	$0.07324	$0.07437	$0.07804	$0.07347	$0.07129
5	MOHAVE	$0.05510	$0.05668	$0.05938	$0.05720	$0.05725	$0.05942	$0.07238	$0.07367	$0.07319	$0.07431	$0.07837	$0.07608	$0.06455
6	SULPHER	$0.05629	$0.05517	$0.05813	$0.05728	$0.05699	$0.05786	$0.07105	$0.07227	$0.07157	$0.07184	$0.07381	$0.07102	$0.06407
7	TRICO	$0.06314	$0.07128	$0.07115	$0.06657	$0.06761	$0.06959	$0.08189	$0.07946	$0.07459	$0.07407	$0.07661	$0.07251	$0.07189
8	AEPCO CLASS A	$0.05766	$0.06047	$0.06312	$0.06078	$0.06091	$0.06252	$0.07479	$0.07446	$0.07306	$0.07342	$0.07616	$0.07302	$0.06678
9														
10	AVERAGE COST PER KWH - PROPOSED REVENUES													
11	ANZA	$0.07078	$0.06197	$0.06520	$0.06083	$0.06111	$0.06269	$0.06351	$0.06289	$0.05662	$0.06063	$0.06124	$0.07247	$0.06311
12	DUNCAN	$0.07366	$0.06079	$0.06082	$0.06192	$0.06170	$0.06635	$0.06933	$0.06759	$0.06185	$0.06313	$0.06800	$0.07820	$0.06541
13	GRAHAM	$0.07578	$0.06436	$0.06062	$0.06056	$0.06067	$0.06426	$0.06820	$0.06895	$0.06405	$0.06710	$0.07360	$0.07703	$0.06608
14	MOHAVE	$0.07110	$0.05854	$0.05982	$0.05888	$0.05863	$0.05942	$0.06217	$0.06693	$0.06488	$0.06723	$0.07128	$0.08005	$0.06391
15	SULPHER	$0.07036	$0.05813	$0.05969	$0.05895	$0.05866	$0.05914	$0.06113	$0.06335	$0.06067	$0.06155	$0.06381	$0.07387	$0.06230
16	TRICO	$0.07644	$0.06469	$0.06298	$0.06112	$0.06086	$0.06204	$0.06522	$0.06925	$0.06431	$0.06616	$0.07062	$0.08089	$0.06611
17	AEPCO CLASS A	$0.07223	$0.06016	$0.06081	$0.05969	$0.05946	$0.06043	$0.06297	$0.06629	$0.06301	$0.06475	$0.06823	$0.07755	$0.06406

Arizona Electric Power Cooperative, Inc.

ANZA ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	6,468	6,132	9,936	11,832	10,716	9,036	5,592	6,564	9,156	7,440	7,596	6,408	96,876
3	kW - Current Year	5,712	7,488	10,608	10,404	9,948	9,684	6,852	5,388	8,860	8,093	7,071	6,304	96,412
4	kW - 12 Month Average	8,010	8,123	8,179	8,060	7,996	8,050	8,155	8,057	8,032	8,087	8,043	8,034	96,826
5	ARM Load Ratio Share	5.34%	5.35%	5.34%	5.30%	5.23%	5.25%	5.31%	5.24%	5.23%	5.27%	5.26%	5.24%	5.28%
6	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
7	KWH - BASE RESOURCES	2,852,721	3,837,518	3,498,387	4,179,337	4,064,489	3,742,041	3,622,972	3,624,544	4,588,670	3,971,349	3,861,740	2,571,184	44,414,952
8	KWH - OTHER EXISTING RESOURCES	881,235	136,762	1,049,481	1,087,043	898,335	525,912	238,616	58,340	94,134	155,241	101,281	1,476,031	6,702,411
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	124,210	41,835	0	0	0	0	0	0	166,045
10														
11	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - SYNCHRONIZATION	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$85,566	$112,170	$158,908	$155,852	$149,021	$145,066	$102,643	$80,712	$132,723	$121,233	$105,924	$94,434	$1,444,252
19	Base Energy Charge Revenue	77,405	82,387	94,277	109,172	105,454	89,342	80,051	76,346	97,075	85,544	82,153	83,899	1,063,105
20	Total Present Base Rate Revenue	$162,971	$194,557	$253,185	$265,024	$254,475	$234,408	$182,694	$157,058	$229,797	$206,777	$188,077	$178,333	$2,507,357
21	FPPCA	61,581	65,544	75,004	86,854	83,896	71,077	63,686	60,738	77,229	68,056	65,358	66,747	845,770
22	Total Present Revenue	$224,551	$260,101	$328,189	$351,878	$338,371	$305,486	$246,379	$217,797	$307,027	$274,833	$253,435	$245,080	$3,353,127
23														
24	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
25	Fixed Demand Charge	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	
26	O&M Demand Charge	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	
27	Base Resource Energy Charge	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	
28	Other Existing Resources Energy Charge	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
29	Additional ARM Resources	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
30	PPFAC	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
33	Fixed Demand Charge Revenue	$49,677	$49,853	$49,684	$49,362	$48,743	$48,925	$49,424	$48,754	$48,719	$49,107	$48,973	$48,802	$590,022
34	O&M Demand Charge Revenue	62,875	63,098	62,885	62,477	61,693	61,923	62,555	61,708	61,662	62,154	61,984	61,768	746,781
35	Base Resource Energy Revenue	92,270	124,123	113,154	135,179	131,465	121,035	117,184	117,235	148,419	128,452	124,907	83,164	1,436,587
36	Other Existing Resources Energy Revenue	59,449	9,226	70,799	73,333	60,603	35,479	16,097	3,936	6,350	10,473	6,833	99,575	452,152
37	Additional ARM Resources	0	0	0	0	8,379	2,822	0	0	0	0	0	0	11,202
38	Total Proposed Base Rate Revenue	$264,271	$246,301	$296,522	$320,352	$310,882	$270,184	$245,260	$231,632	$265,150	$250,185	$242,695	$293,309	$3,236,743
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$264,271	$246,301	$296,522	$320,352	$310,882	$270,184	$245,260	$231,632	$265,150	$250,185	$242,695	$293,309	$3,236,743
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$26,986	$781	($46,339)	($44,013)	($38,586)	($34,218)	$9,336	$29,750	($22,342)	($9,972)	$5,033	$16,136	($107,449)
44	Change in Base Energy Charge Revenue	74,314	50,963	89,676	99,340	94,992	69,994	53,230	44,824	57,695	53,381	49,586	98,840	836,836
45	Change in Base Rate Revenue	$101,300	$51,744	$43,337	$55,328	$56,406	$35,776	$62,566	$74,574	$35,353	$43,408	$54,618	$114,976	$729,386
46	Change in FPPCA Revenue	(61,581)	(65,544)	(75,004)	(86,854)	(83,896)	(71,077)	(63,686)	(60,738)	(77,229)	(68,056)	(65,358)	(66,747)	(845,770)
47	Change in Total Revenue	$39,720	($13,801)	($31,667)	($31,526)	($27,489)	($35,302)	($1,119)	$13,836	($41,876)	($24,648)	($10,740)	$48,229	($116,384)
48	Percentage Change in Base Rate Revenue	62.16%	26.60%	17.12%	20.88%	22.17%	15.26%	34.25%	47.48%	15.38%	20.99%	29.04%	64.47%	29.09%
49	Percentage Change in Total Revenue	17.69%	-5.31%	-9.65%	-8.96%	-8.12%	-11.56%	-0.45%	6.35%	-13.64%	-8.97%	-4.24%	19.68%	-3.47%

Arizona Electric Power Cooperative, Inc.

DUNCAN ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	3,100	5,640	6,660	6,020	6,520	3,720	4,520	3,320	4,520	4,320	4,180	3,260	55,780
3	kW - Current Year	3,860	6,040	6,960	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
4	kW - 12 Month Average	4,712	4,745	4,770	4,763	4,772	4,908	4,867	4,822	4,803	4,768	4,745	4,765	57,440
5	ARM Load Ratio Share	3.14%	3.13%	3.11%	3.13%	3.12%	3.20%	3.17%	3.13%	3.13%	3.11%	3.10%	3.11%	3.13%
6	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
7	KWH - BASE RESOURCES	1,531,549	2,339,466	2,479,519	2,349,355	2,361,719	1,997,532	1,800,946	1,875,660	2,246,044	2,142,874	1,835,257	1,260,715	24,220,635
8	KWH - OTHER EXISTING RESOURCES	473,111	83,374	743,831	611,065	521,988	280,736	118,614	30,190	46,076	83,766	48,133	723,735	3,764,620
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	72,174	22,332	0	0	0	0	0	0	94,506
10														
11	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$57,823	$90,479	$104,261	$88,981	$99,168	$80,293	$60,220	$41,644	$64,414	$58,422	$58,422	$52,430	$856,556
19	Base Energy Charge Revenue	41,557	50,225	66,820	61,370	61,275	47,691	39,792	39,508	47,516	46,158	39,043	41,138	582,093
20	Total Present Base Rate Revenue	$99,379	$140,705	$171,081	$150,351	$160,443	$127,984	$100,012	$81,153	$111,930	$104,580	$97,465	$93,568	$1,438,650
21	FPPCA	33,061	39,958	53,160	48,824	48,749	37,942	31,658	31,431	37,802	36,722	31,061	32,728	463,094
22	Total Present Revenue	$132,440	$180,662	$224,241	$199,174	$209,192	$165,926	$131,670	$112,584	$149,731	$141,302	$128,526	$126,295	$1,901,744
23														
24	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
25	Fixed Demand Charge	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	
26	O&M Demand Charge	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	
27	Base Resource Energy Charge	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	
28	Other Existing Resources Energy Charge	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
29	Additional ARM Resources	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
33	Fixed Demand Charge Revenue	$29,221	$29,121	$28,976	$29,172	$29,087	$29,831	$29,495	$29,177	$29,134	$28,956	$28,892	$28,944	$350,005
34	O&M Demand Charge Revenue	36,984	36,858	36,674	36,923	36,815	37,757	37,331	36,929	36,874	36,649	36,568	36,633	442,995
35	Base Resource Energy Revenue	49,537	75,669	80,199	75,989	76,389	64,610	58,251	60,668	72,648	69,311	59,361	40,777	783,409
36	Other Existing Resources Energy Revenu	31,917	5,625	50,180	41,223	35,214	18,939	8,002	2,037	3,108	5,651	3,247	48,824	253,965
37	Additional ARM Resources	0	0	0	0	4,869	1,507	0	0	0	0	0	0	6,375
38	Total Proposed Base Rate Revenue	$147,659	$147,274	$196,029	$183,308	$182,375	$152,642	$133,078	$128,810	$141,764	$140,566	$128,067	$155,178	$1,836,750
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$147,659	$147,274	$196,029	$183,308	$182,375	$152,642	$133,078	$128,810	$141,764	$140,566	$128,067	$155,178	$1,836,750
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$8,383	($24,499)	($38,611)	($22,886)	($33,265)	($12,705)	$6,606	$24,461	$1,594	$7,183	$7,037	$13,147	($63,556)
44	Change in Base Energy Charge Revenue	39,897	31,068	63,559	55,843	55,196	37,363	26,460	23,196	28,240	28,803	23,565	48,464	461,656
45	Change in Base Rate Revenue	$48,280	$6,569	$24,948	$32,957	$21,932	$24,658	$33,066	$47,657	$29,834	$35,986	$30,602	$61,611	$398,100
46	Change in FPPCA Revenue	(33,061)	(39,958)	(53,160)	(48,824)	(48,749)	(37,942)	(31,658)	(31,431)	(37,802)	(36,722)	(31,061)	(32,728)	(463,094)
47	Change in Total Revenue	$15,219	($33,389)	($28,211)	($15,867)	($26,817)	($13,284)	$1,409	$16,226	($7,968)	($736)	($459)	$28,883	($64,994)
48	Percentage Change in Base Rate Revenu	48.58%	4.67%	14.58%	21.92%	13.67%	19.27%	33.06%	58.73%	26.65%	34.41%	31.40%	65.85%	27.67%
49	Percentage Change in Total Revenue	11.49%	-18.48%	-12.58%	-7.97%	-12.82%	-8.01%	1.07%	14.41%	-5.32%	-0.52%	-0.36%	22.87%	-3.42%

Arizona Electric Power Cooperative, Inc.

GRAHAM ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	21,235	29,349	40,099	39,125	36,733	30,341	27,052	18,498	21,916	20,119	19,731	19,458	323,658
3	kW - Current Year	20,966	31,511	39,951	39,726	36,986	32,263	24,988	18,448	20,642	19,992	18,818	20,271	324,562
4	kW - 12 Month Average	26,949	27,129	27,117	27,167	27,188	27,348	27,176	27,172	27,066	27,055	26,979	27,047	325,394
5	ARM Load Ratio Share	17.95%	17.88%	17.69%	17.87%	17.80%	17.65%	17.69%	17.66%	17.63%	17.64%	17.64%	17.64%	17.75%
6	KWH - TOTAL	10,775,112	12,244,130	18,499,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
7	KWH - BASE RESOURCES	8,232,123	11,822,768	14,230,236	14,265,620	14,106,426	11,983,452	10,392,305	10,170,848	11,758,796	10,715,505	8,985,666	7,418,708	134,082,474
8	KWH - OTHER EXISTING RESOURCES	2,542,989	421,342	4,268,930	3,710,478	3,117,807	1,684,170	684,458	163,708	241,224	418,873	235,665	4,258,835	21,748,479
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	431,089	133,972	0	0	0	0	0	0	565,062
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$314,071	$472,035	$598,466	$595,095	$554,050	$483,300	$374,320	$276,351	$309,217	$299,480	$281,894	$303,660	$4,861,939
19	Base Energy Charge Revenue	223,368	253,821	383,488	372,645	365,995	286,107	229,621	214,235	248,760	230,816	191,158	242,075	3,242,089
20	Total Present Base Rate Revenue	$537,439	$725,856	$981,954	$967,740	$920,045	$769,407	$603,942	$490,586	$557,978	$530,296	$473,052	$545,735	$8,104,028
21	FPPCA	177,704	201,931	305,090	296,463	291,173	227,617	182,679	170,438	197,905	183,629	152,079	192,587	2,579,296
22	Total Present Revenue	$715,143	$927,787	$1,287,044	$1,264,203	$1,211,218	$997,024	$786,620	$661,025	$755,883	$713,925	$625,131	$738,322	$10,683,325
23														
24	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
25	Fixed Demand Charge	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	
26	O&M Demand Charge	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	
27	Base Resource Energy Charge	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	
28	Other Existing Resources Energy Charge	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
29	Additional ARM Resources	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
33	Fixed Demand Charge Revenue	$167,134	$166,499	$164,725	$166,360	$165,735	$166,212	$164,703	$164,423	$164,162	$164,293	$164,271	$164,288	$1,982,825
34	O&M Demand Charge Revenue	211,538	210,736	208,490	210,585	209,768	210,372	208,462	208,108	207,777	207,943	207,915	207,936	2,509,628
35	Base Resource Energy Revenue	266,265	382,404	460,272	461,417	456,268	387,601	336,136	328,973	380,335	346,590	290,638	239,956	4,336,855
36	Other Existing Resources Energy Revenue	171,553	28,424	287,987	250,313	210,331	113,616	46,174	11,044	16,273	28,258	15,898	287,305	1,467,175
37	Additional ARM Resources	0	0	0	0	29,082	9,038	0	0	0	0	0	0	38,120
38	Total Proposed Base Rate Revenue	$816,490	$788,064	$1,121,473	$1,088,695	$1,071,183	$886,838	$755,475	$712,548	$768,547	$747,083	$678,723	$899,485	$10,334,603
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$816,490	$788,064	$1,121,473	$1,088,695	$1,071,183	$886,838	$755,475	$712,548	$768,547	$747,083	$678,723	$899,485	$10,334,603
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$64,601	($94,800)	($225,251)	($218,130)	($178,548)	($106,716)	($1,155)	$96,180	$62,722	$72,756	$90,293	$68,564	($369,485)
44	Change in Base Energy Charge Revenue	214,450	157,008	364,771	339,085	329,685	224,148	152,689	125,781	147,847	144,032	115,379	285,186	2,600,061
45	Change in Base Rate Revenue	$279,051	$62,208	$139,520	$120,955	$151,138	$117,432	$151,534	$221,961	$210,569	$216,787	$205,671	$353,750	$2,230,575
46	Change in FPPCA Revenue	(177,704)	(201,931)	(305,090)	(296,463)	(291,173)	(227,617)	(182,679)	(170,438)	(197,905)	(183,629)	(152,079)	(192,587)	(2,579,296)
47	Change in Total Revenue	$101,347	($139,723)	($165,570)	($175,509)	($140,035)	($110,185)	($31,145)	$51,523	$12,664	$33,158	$53,592	$161,163	($348,721)
48	Percentage Change in Base Rate Revenue	51.92%	8.57%	14.21%	12.50%	16.43%	15.26%	25.09%	45.24%	37.74%	40.88%	43.48%	64.82%	27.52%
49	Percentage Change in Total Revenue	14.17%	-15.06%	-12.86%	-13.88%	-11.56%	-11.05%	-3.96%	7.79%	1.68%	4.64%	8.57%	21.83%	-3.26%

Arizona Electric Power Cooperative, Inc.

MOHAVE ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$855,113	$855,113	$855,113	$855,113	$855,113	$841,539	$855,113	$855,113	$855,113	$841,248	$855,113	$841,405	$10,220,208
7														
8	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
9	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
10	KWH - BASE RESOURCES	50,755,139	78,652,286	76,386,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
11	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,670,515
12	Demand Revenue	$1,814,798	$2,046,290	$2,167,510	$2,168,113	$2,167,010	$2,131,670	$1,926,246	$1,646,083	$1,719,895	$1,680,468	$1,698,967	$1,565,038	$22,732,087
13	Base Energy Charge Revenue	1,612,943	1,703,368	1,755,123	1,919,342	1,913,881	1,723,372	1,527,516	1,243,970	1,322,828	1,241,118	1,096,053	1,087,114	18,146,629
14	Total Present Base Rate Revenue	$3,427,741	$3,749,659	$3,922,633	$4,087,455	$4,080,891	$3,855,042	$3,453,762	$2,890,053	$3,042,723	$2,921,585	$2,795,020	$2,652,152	$40,878,716
15	FPPCA	1,184,537	1,250,945	1,288,953	1,409,555	1,405,545	1,265,635	1,121,800	913,565	971,478	911,470	804,936	798,371	13,326,790
16	Total Present Revenue	$4,612,278	$5,000,603	$5,211,586	$5,497,011	$5,486,436	$5,120,677	$4,575,562	$3,803,618	$4,014,201	$3,833,055	$3,599,956	$3,450,523	$54,205,506
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	
20	O&M Demand Charge	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	
21	Base Resource Energy Charge	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	
22	Other Existing Resources Energy Charge	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$9,179,703
27	O&M Demand Charge Revenue	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	15,298,589
28	Base Resource Energy Revenue	1,631,645	2,528,466	2,455,622	2,594,195	2,612,518	2,472,658	2,217,326	1,887,770	2,008,670	1,871,542	1,673,996	1,271,666	25,226,075
29	Other Existing Resources Energy Revenue	1,860,829	241,921	569,519	817,930	760,603	427,710	324,157	88,450	91,425	113,708	55,049	886,267	6,237,567
30	Total Proposed Base Rate Revenue	$5,532,332	$4,810,244	$5,064,999	$5,451,982	$5,412,978	$4,940,226	$4,581,341	$4,016,078	$4,139,952	$4,025,108	$3,768,902	$4,197,791	$55,941,934
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$5,532,332	$4,810,244	$5,064,999	$5,451,982	$5,412,978	$4,940,226	$4,581,341	$4,016,078	$4,139,952	$4,025,108	$3,768,902	$4,197,791	$55,941,934
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$225,060	($6,433)	($127,653)	($128,255)	($127,152)	($91,812)	$113,612	$393,775	$319,962	$359,390	$340,891	$474,820	$1,746,204
36	Change in Energy Charge Revenue	1,879,531	1,067,018	1,270,019	1,492,782	1,459,239	1,176,997	1,013,968	732,250	777,267	744,133	632,991	1,070,819	13,317,014
37	Change in Base Rate Revenue	$2,104,591	$1,060,585	$1,142,366	$1,364,527	$1,332,087	$1,085,184	$1,127,579	$1,126,025	$1,097,230	$1,103,523	$973,882	$1,545,639	$15,063,218
38	Change in FPPCA Revenue	(1,184,537)	(1,250,945)	(1,288,953)	(1,409,555)	(1,405,545)	(1,265,635)	(1,121,800)	(913,565)	(971,478)	(911,470)	(804,936)	(798,371)	(13,326,790)
39	Change in Total Revenue	$920,053	($190,359)	($146,587)	($45,028)	($73,457)	($180,451)	$5,780	$212,460	$125,752	$192,053	$168,946	$747,268	$1,736,428
40	Percentage Change in Base Rate Revenue	61.40%	28.28%	29.12%	33.38%	32.64%	28.15%	32.65%	38.96%	36.08%	37.77%	34.84%	58.28%	36.85%
41	Percentage Change in Total Revenue	19.95%	-3.81%	-2.81%	-0.82%	-1.34%	-3.52%	0.13%	5.59%	3.13%	5.01%	4.69%	21.66%	3.20%

Arizona Electric Power Cooperative, Inc.

SULPHUR SPRINGS ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$9,089,148
7														
8	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
9	KW	131,134	137,934	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	138,700	128,900	1,629,806
10	KWH - BASE RESOURCES	45,109,060	71,215,789	67,765,404	69,476,926	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	38,296,091	738,282,902
11	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
12	Demand Revenue	$1,709,462	$1,758,830	$1,824,896	$1,771,898	$1,757,378	$1,744,310	$1,716,722	$1,616,534	$1,784,966	$1,778,911	$1,764,391	$1,693,243	$20,921,540
13	Base Energy Charge Revenue	1,446,096	1,558,774	1,553,892	1,562,858	1,569,492	1,501,590	1,434,581	1,287,408	1,460,597	1,440,640	1,326,890	1,416,282	17,559,098
14	Total Present Base Rate Revenue	$3,155,558	$3,317,604	$3,378,788	$3,334,756	$3,326,869	$3,245,900	$3,151,303	$2,903,941	$3,245,563	$3,219,551	$3,091,281	$3,109,525	$38,480,637
15	FPPCA	1,115,571	1,202,495	1,198,729	1,205,646	1,210,763	1,158,381	1,106,688	993,153	1,126,758	1,111,362	1,023,611	1,092,571	13,545,728
16	Total Present Revenue	$4,271,129	$4,520,099	$4,577,516	$4,540,401	$4,537,632	$4,404,281	$4,257,990	$3,897,095	$4,372,320	$4,330,913	$4,114,892	$4,202,096	$52,026,365
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	
20	O&M Demand Charge	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	
21	Base Resource Energy Charge	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	
22	Other Existing Resources Energy Charge	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$8,128,396
27	O&M Demand Charge Revenue	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	13,546,516
28	Base Resource Energy Revenue	1,456,357	2,299,219	2,187,822	2,243,079	2,266,032	2,208,312	2,056,423	1,889,857	2,093,151	2,030,752	1,868,240	1,236,399	23,835,642
29	Other Existing Resources Energy Revenue	1,645,489	265,575	480,184	394,804	368,707	269,395	367,667	238,139	375,504	440,258	409,960	2,004,284	7,259,986
30	Total Proposed Base Rate Revenue	$4,908,089	$4,371,037	$4,474,250	$4,444,126	$4,440,982	$4,283,950	$4,230,332	$3,934,239	$4,274,897	$4,277,252	$4,084,462	$5,046,925	$52,770,540
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$4,908,089	$4,371,037	$4,474,250	$4,444,126	$4,440,982	$4,283,950	$4,230,332	$3,934,239	$4,274,897	$4,277,252	$4,084,462	$5,046,925	$52,770,540
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$96,781	$47,413	($18,653)	$34,345	$48,865	$61,933	$89,521	$189,709	$21,277	$27,332	$41,852	$113,000	$753,372
36	Change in Energy Charge Revenue	1,655,750	1,006,020	1,114,115	1,075,026	1,065,248	976,117	989,509	840,589	1,008,058	1,030,370	951,329	1,824,400	13,536,530
37	Change in Base Rate Revenue	$1,752,531	$1,053,433	$1,095,462	$1,109,370	$1,114,112	$1,038,050	$1,079,030	$1,030,298	$1,029,335	$1,057,701	$993,181	$1,937,400	$14,289,903
38	Change in FPPCA Revenue	(1,115,571)	(1,202,495)	(1,198,729)	(1,205,646)	(1,210,763)	(1,158,381)	(1,106,688)	(993,153)	(1,126,758)	(1,111,362)	(1,023,611)	(1,092,571)	(13,545,728)
39	Change in Total Revenue	$636,960	($149,063)	($103,267)	($96,275)	($96,651)	($120,331)	($27,658)	$37,144	($97,423)	($53,661)	($30,430)	$844,828	$744,175
40	Percentage Change in Base Rate Revenue	55.54%	31.75%	32.42%	33.27%	33.49%	31.98%	34.24%	35.48%	31.72%	32.85%	32.13%	62.31%	37.14%
41	Percentage Change in Total Revenue	14.91%	-3.30%	-2.26%	-2.12%	-2.13%	-2.73%	-0.65%	0.95%	-2.23%	-1.24%	-0.74%	20.10%	1.43%

Arizona Electric Power Cooperative, Inc.

TRICO ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	88,830	110,939	146,640	163,888	146,704	139,833	110,067	87,080	92,923	87,572	84,462	69,545	1,328,483
3	kW - Current Year	85,906	125,972	164,592	149,858	155,646	141,128	116,545	91,700	90,417	85,278	81,248	73,021	1,361,311
4	kW - 12 Month Moving Average	110,463	111,716	113,212	112,043	112,788	112,896	113,436	113,821	113,612	113,421	113,153	113,443	1,354,003
5	ARM Load Ratio Share	73.58%	73.64%	73.86%	73.70%	73.84%	73.69%	73.84%	73.97%	74.01%	73.97%	73.99%	74.01%	73.84%
6	KWH - TOTAL	43,348,839	49,883,272	69,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
7	KWH - BASE RESOURCES	33,118,261	48,166,700	53,187,964	57,321,553	58,001,937	53,834,841	47,593,662	42,254,430	48,946,556	46,212,451	40,692,756	27,756,481	557,087,594
8	KWH - OTHER EXISTING RESOURCES	10,230,578	1,716,572	15,955,862	14,909,296	12,819,609	7,566,021	3,134,613	680,119	1,004,108	1,806,460	1,067,241	15,934,077	86,824,555
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	1,772,527	601,861	0	0	0	0	0	0	2,374,388
10														
11	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$1,286,872	$1,887,061	$2,465,588	$2,244,873	$2,331,577	$2,114,097	$1,745,844	$1,373,666	$1,354,447	$1,277,464	$1,217,095	$1,093,855	$20,392,439
19	Base Energy Charge Revenue	898,621	1,034,080	1,433,352	1,497,345	1,504,875	1,285,316	1,051,597	890,033	1,035,477	995,432	865,685	905,705	13,397,520
20	Total Present Base Rate Revenue	$2,185,493	$2,921,141	$3,898,940	$3,742,218	$3,836,452	$3,399,414	$2,797,441	$2,263,699	$2,389,924	$2,272,896	$2,082,780	$1,999,560	$33,789,959
21	FPPCA	714,913	822,679	1,140,326	1,191,237	1,197,228	1,022,554	836,615	708,080	823,791	791,932	688,709	720,548	10,658,613
22	Total Present Revenue	$2,900,406	$3,743,820	$5,039,266	$4,933,456	$5,033,680	$4,421,968	$3,634,056	$2,971,779	$3,213,715	$3,064,828	$2,771,489	$2,720,108	$44,448,572
23														
24	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
25	Fixed Demand Charge	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	$931,105	
26	O&M Demand Charge	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	$1,178,484	
27	Base Resource Energy Charge	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	$0.03234	
28	Other Existing Resources Energy Charge	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
29	Additional ARM Resources	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	$0.06746	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
33	Fixed Demand Charge Revenue	$685,074	$685,631	$687,720	$686,190	$687,540	$686,137	$687,483	$688,750	$689,091	$688,749	$688,970	$689,072	$8,250,406
34	O&M Demand Charge Revenue	867,086	867,792	870,435	868,499	870,208	868,432	870,136	871,740	872,171	871,738	872,017	872,147	10,442,402
35	Base Resource Energy Revenue	1,071,200	1,557,937	1,720,348	1,854,047	1,876,054	1,741,271	1,539,402	1,366,706	1,583,161	1,494,727	1,316,194	897,775	18,018,821
36	Other Existing Resources Energy Revenue	690,166	115,802	1,076,399	1,005,797	864,824	510,412	211,464	45,882	67,738	121,866	71,997	1,074,930	5,857,276
37	Additional ARM Resources	0	0	0	0	119,577	40,602	0	0	0	0	0	0	160,179
38	Total Proposed Base Rate Revenue	$3,313,525	$3,227,161	$4,354,902	$4,414,533	$4,418,203	$3,846,854	$3,308,485	$2,973,078	$3,212,160	$3,177,080	$2,949,178	$3,533,922	$42,729,083
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$3,313,525	$3,227,161	$4,354,902	$4,414,533	$4,418,203	$3,846,854	$3,308,485	$2,973,078	$3,212,160	$3,177,080	$2,949,178	$3,533,922	$42,729,083
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$265,288	($333,638)	($907,433)	($690,184)	($773,829)	($559,528)	($188,225)	$186,824	$206,815	$283,023	$343,892	$467,364	($1,699,631)
44	Change in Base Energy Charge Revenue	862,744	639,658	1,363,396	1,362,499	1,355,580	1,006,968	699,269	522,554	615,422	621,161	522,507	1,066,999	10,638,756
45	Change in Base Rate Revenue	$1,128,032	$306,020	$455,962	$672,315	$581,751	$447,440	$511,044	$709,379	$822,236	$904,184	$866,398	$1,534,363	$8,939,125
46	Change in FPPCA Revenue	(714,913)	(822,679)	(1,140,326)	(1,191,237)	(1,197,228)	(1,022,554)	(836,615)	(708,080)	(823,791)	(791,932)	(688,709)	(720,548)	(10,658,613)
47	Change in Total Revenue	$413,119	($516,659)	($684,364)	($518,923)	($615,477)	($575,114)	($325,571)	$1,298	($1,554)	$112,252	$177,689	$813,814	($1,719,488)
48	Percentage Change in Base Rate Revenue	51.61%	10.48%	11.69%	17.97%	15.16%	13.16%	18.27%	31.34%	34.40%	39.78%	41.60%	76.74%	26.45%
49	Percentage Change in Total Revenue	14.24%	-13.80%	-13.58%	-10.52%	-12.23%	-13.01%	-8.96%	0.04%	-0.05%	3.66%	6.41%	29.92%	-3.87%

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED PRESENT WITH SYNCHRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	PRESENT REVENUES w/ FPPAC SYNCHRONIZED													
2	FULL REQUIREMENTS													
3	Demand Revenue	$1,744,331	$2,561,745	$3,327,223	$3,084,801	$3,133,816	$2,822,756	$2,283,027	$1,772,374	$1,860,801	$1,756,600	$1,663,334	$1,544,378	$27,555,186
4	Base Energy Revenue	1,240,951	1,420,513	1,977,937	2,040,532	2,037,600	1,708,457	1,401,062	1,220,123	1,428,828	1,357,950	1,178,039	1,272,817	18,284,808
5	Total Present Base Rate Revenue	$2,985,282	$3,982,258	$5,305,159	$5,125,333	$5,171,416	$4,531,213	$3,684,089	$2,992,497	$3,289,628	$3,114,550	$2,841,373	$2,817,195	$45,839,993
6	FPPCA	987,259	1,130,112	1,573,579	1,623,378	1,621,045	1,359,190	1,114,637	970,689	1,136,727	1,080,339	937,208	1,012,610	14,546,774
7	Total Adjusted Present Revenue	$3,972,541	$5,112,370	$6,878,739	$6,748,711	$6,792,461	$5,890,404	$4,798,726	$3,963,185	$4,426,356	$4,194,889	$3,778,581	$3,829,805	$60,386,767
8														
9	PARTIAL REQUIREMENTS													
10	Fixed / O&M Charge Revenue	$3,524,260	$3,805,120	$3,992,406	$3,940,011	$3,924,387	$3,875,980	$3,642,968	$3,262,617	$3,504,861	$3,459,379	$3,463,358	$3,258,281	$43,653,627
11	Base Energy Revenue	3,059,039	3,262,142	3,309,014	3,482,200	3,483,373	3,224,962	2,962,096	2,531,378	2,783,425	2,681,757	2,422,943	2,503,396	35,705,726
12	Total Present Base Rate Revenue	$6,583,299	$7,067,263	$7,301,421	$7,422,211	$7,407,760	$7,100,942	$6,605,064	$5,793,994	$6,288,286	$6,141,136	$5,886,301	$5,761,677	$79,359,353
13	FPPCA	2,300,108	2,453,440	2,487,682	2,615,201	2,616,308	2,424,017	2,228,487	1,906,718	2,098,235	2,022,832	1,828,547	1,890,943	26,872,518
14	Total Adjusted Present Revenue	$8,883,407	$9,520,703	$9,789,102	$10,037,412	$10,024,068	$9,524,958	$8,833,552	$7,700,712	$8,386,521	$8,163,968	$7,714,848	$7,652,620	$106,231,871
15														
16	TOTAL CLASS A													
17	Demand Revenue	$5,268,591	$6,366,865	$7,319,629	$7,024,812	$7,058,203	$6,698,736	$5,925,995	$5,034,990	$5,365,662	$5,215,978	$5,126,692	$4,802,659	$71,208,813
18	Base Energy Revenue	4,299,990	4,682,656	5,286,951	5,522,732	5,520,973	4,933,419	4,363,158	3,751,501	4,212,252	4,039,707	3,600,982	3,776,213	53,990,534
19	Total Present Base Rate Revenue	$9,568,581	$11,049,521	$12,606,580	$12,547,544	$12,579,176	$11,632,155	$10,289,153	$8,786,491	$9,577,914	$9,255,686	$8,727,674	$8,578,872	$125,199,347
20	FPPCA	3,287,367	3,583,552	4,061,261	4,238,578	4,237,353	3,783,207	3,343,125	2,877,407	3,234,962	3,103,171	2,765,755	2,903,553	41,419,292
21	Total Adjusted Present Revenue	$12,855,948	$14,633,073	$16,667,841	$16,786,123	$16,816,529	$15,415,362	$13,632,278	$11,663,898	$12,812,877	$12,358,857	$11,493,429	$11,482,425	$166,618,638
22														
23	PROPOSED REVENUES													
24	FULL REQUIREMENTS													
25	Demand Revenue	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$2,109,589	$25,315,064
26	Base Energy Revenue	2,432,357	2,299,210	3,859,338	3,897,299	3,873,054	3,046,930	2,332,710	1,936,479	2,276,032	2,205,326	1,889,075	2,772,305	32,822,116
27	Total Proposed Base Rate Revenue	$4,541,945	$4,408,799	$5,968,927	$6,006,887	$5,982,642	$5,156,519	$4,442,299	$4,046,068	$4,387,621	$4,314,915	$3,998,664	$4,881,894	$58,137,179
28	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total Adjusted Proposed Revenue	$4,541,945	$4,408,799	$5,968,927	$6,006,887	$5,982,642	$5,156,519	$4,442,299	$4,046,068	$4,387,621	$4,314,915	$3,998,664	$4,881,894	$58,137,179
30														
31	PARTIAL REQUIREMENTS													
32	Fixed / O&M Charge Revenue	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$3,846,100	$46,153,204
33	Base Energy Revenue	6,594,320	5,335,180	5,693,148	6,050,008	6,007,860	5,378,076	4,965,573	4,104,217	4,568,749	4,456,260	4,007,264	5,398,616	62,559,271
34	Total Proposed Base Rate Revenue	$10,440,420	$9,181,281	$9,539,249	$9,896,108	$9,853,960	$9,224,176	$8,811,674	$7,950,317	$8,414,850	$8,302,360	$7,853,364	$9,244,716	$108,712,474
35	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total Adjusted Proposed Revenue	$10,440,420	$9,181,281	$9,539,249	$9,896,108	$9,853,960	$9,224,176	$8,811,674	$7,950,317	$8,414,850	$8,302,360	$7,853,364	$9,244,716	$108,712,474
37														
38	TOTAL CLASS A													
39	Demand Revenue	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$71,468,267
40	Base Energy Revenue	9,026,677	7,634,390	9,552,486	9,947,307	9,880,913	8,425,006	7,298,283	6,040,696	6,846,781	6,661,586	5,896,339	8,170,921	95,381,386
41	Total Proposed Base Rate Revenue	$14,982,366	$13,590,079	$15,508,175	$15,902,995	$15,836,602	$14,380,695	$13,253,972	$11,996,385	$12,802,470	$12,617,275	$11,852,028	$14,126,610	$166,849,654
42	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Adjusted Proposed Revenue	$14,982,366	$13,590,079	$15,508,175	$15,902,995	$15,836,602	$14,380,695	$13,253,972	$11,996,385	$12,802,470	$12,617,275	$11,852,028	$14,126,610	$166,849,654
44														
45	PROPOSED REVENUE CHANGES													
46	FULL REQUIREMENTS													
47	Demand Revenue	$365,258	($452,156)	($1,217,634)	($975,213)	($1,024,227)	($713,168)	($173,436)	$337,215	$248,788	$352,989	$446,254	$565,211	($2,240,122)
48	Base Energy Revenue	1,191,406	878,697	1,881,402	1,856,767	1,835,454	1,338,473	931,649	716,356	849,204	847,376	711,036	1,499,488	14,537,308
49	Change in Base Rate Revenue	$1,556,663	$426,541	$663,767	$881,554	$811,227	$625,306	$758,210	$1,053,571	$1,097,992	$1,200,365	$1,157,291	$2,064,699	$12,297,186
50	FPPCA	(987,259)	(1,130,112)	(1,573,579)	(1,623,378)	(1,621,045)	(1,359,190)	(1,114,637)	(970,689)	(1,136,727)	(1,080,339)	(937,208)	(1,012,610)	(14,546,774)
51	Total Revenue Change	$569,405	($703,572)	($909,812)	($741,824)	($809,819)	($733,885)	($356,427)	$82,882	($38,735)	$120,026	$220,083	$1,052,089	($2,249,588)
52	Percent Change in Base Rate Revenue	23.65%	6.04%	9.09%	11.88%	10.95%	8.81%	11.48%	18.18%	17.46%	19.55%	19.66%	35.84%	15.50%
53	Percent Change in Total Revenue	14.33%	-13.76%	-13.23%	-10.99%	-11.92%	-12.46%	-7.43%	2.09%	-0.88%	2.86%	5.82%	27.47%	-3.73%
54														
55	PARTIAL REQUIREMENTS													
56	Fixed / O&M Charge Revenue	$321,841	$40,980	($146,306)	($93,911)	($78,287)	($29,879)	$203,132	$583,484	$341,239	$386,722	$382,743	$587,819	$2,499,577
57	Base Energy Revenue	3,535,281	2,073,038	2,384,134	2,567,808	2,524,487	2,153,114	2,003,477	1,572,839	1,785,325	1,774,503	1,584,321	2,895,219	26,853,544
58	Change in Base Rate Revenue	$3,857,122	$2,114,018	$2,237,828	$2,473,897	$2,446,200	$2,123,234	$2,206,609	$2,156,323	$2,126,564	$2,161,224	$1,967,063	$3,483,039	$29,353,121
59	FPPCA	(2,300,108)	(2,453,440)	(2,487,682)	(2,615,201)	(2,616,308)	(2,424,017)	(2,228,487)	(1,906,718)	(2,098,235)	(2,022,832)	(1,828,547)	(1,890,943)	(26,872,518)
60	Total Revenue Change	$1,557,013	($339,422)	($249,854)	($141,304)	($170,108)	($300,782)	($21,878)	$249,604	$28,329	$138,392	$138,516	$1,592,096	$2,480,603
61	Percent Change in Base Rate Revenue	58.59%	29.91%	30.65%	33.33%	33.02%	29.90%	33.41%	37.22%	33.82%	35.19%	33.42%	60.45%	36.99%
62	Percent Change in Total Revenue	17.53%	-3.57%	-2.55%	-1.41%	-1.70%	-3.16%	-0.25%	3.24%	0.34%	1.70%	1.80%	20.80%	2.34%
63														
64	TOTAL CLASS A													
65	Demand Revenue	$687,098	($411,176)	($1,363,940)	($1,069,123)	($1,102,514)	($743,047)	$29,694	$920,699	$590,027	$739,711	$828,997	$1,153,030	$259,455
66	Base Energy Revenue	4,726,687	2,951,734	4,265,535	4,424,575	4,359,941	3,491,587	2,935,125	2,289,195	2,634,529	2,621,879	2,295,357	4,394,708	41,390,852
67	Percent Change in Base Rate Revenue	$5,413,785	$2,540,559	$2,901,595	$3,355,451	$3,257,426	$2,748,540	$2,964,819	$3,209,894	$3,224,556	$3,361,589	$3,124,354	$5,547,738	$41,650,307
68	FPPCA	(3,287,367)	(3,583,552)	(4,061,261)	(4,238,578)	(4,237,353)	(3,783,207)	(3,343,125)	(2,877,407)	(3,234,962)	(3,103,171)	(2,765,755)	(2,903,553)	(41,419,292)
69	Total Revenue Change	$2,126,418	($1,042,994)	($1,159,666)	($883,127)	($979,926)	($1,034,667)	($378,305)	$332,487	($10,406)	$258,418	$358,599	$2,644,185	$231,015
70	Percent Change in Base Rate Revenue	56.56%	22.99%	23.02%	26.74%	25.90%	23.63%	28.81%	36.53%	33.67%	36.32%	35.80%	64.67%	33.27%
71	Percent Change in Total Revenue	16.54%	-7.13%	-6.96%	-5.26%	-5.83%	-6.71%	-2.78%	2.85%	-0.08%	2.09%	3.12%	23.03%	0.14%

Arizona Electric Power Cooperative, Inc.

ANALYSIS OF REVENUE BY DETAILED CLASS WITH SYNCHRONIZED FPPCA - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	AVERAGE COST PER KWH - PRESENT REVENUES													
2	ANZA	$0.06014	$0.06545	$0.07216	$0.06682	$0.06652	$0.07088	$0.06380	$0.05914	$0.06556	$0.06660	$0.06395	$0.06056	$0.06538
3	DUNCAN	$0.06607	$0.07457	$0.06957	$0.06728	$0.07077	$0.07212	$0.06859	$0.05907	$0.06532	$0.06346	$0.06824	$0.06364	$0.06773
4	GRAHAM	$0.06637	$0.07577	$0.06957	$0.07033	$0.06860	$0.07224	$0.07102	$0.06396	$0.06299	$0.06412	$0.06779	$0.06323	$0.06831
5	MOHAVE	$0.05928	$0.06086	$0.06155	$0.05937	$0.05943	$0.06160	$0.06210	$0.06338	$0.06291	$0.06402	$0.06809	$0.06580	$0.06192
6	SULPHER	$0.06123	$0.06011	$0.06107	$0.06022	$0.05993	$0.06080	$0.06153	$0.06275	$0.06206	$0.06232	$0.06429	$0.06151	$0.06142
7	TRICO	$0.06691	$0.07505	$0.07288	$0.06830	$0.06934	$0.07132	$0.07164	$0.06922	$0.06434	$0.06383	$0.06637	$0.06226	$0.06878
8	AEPCO CLASS A	$0.06198	$0.06478	$0.06535	$0.06301	$0.06314	$0.06477	$0.06477	$0.06445	$0.06306	$0.06342	$0.06616	$0.06303	$0.06397
9														
10	AVERAGE COST PER KWH - PROPOSED REVENUES													
11	ANZA	$0.07078	$0.06197	$0.06520	$0.06083	$0.06111	$0.06269	$0.06351	$0.06289	$0.05662	$0.06063	$0.06124	$0.07247	$0.06311
12	DUNCAN	$0.07366	$0.06079	$0.06082	$0.06192	$0.06170	$0.06635	$0.06933	$0.06759	$0.06185	$0.06313	$0.06800	$0.07820	$0.06541
13	GRAHAM	$0.07578	$0.06436	$0.06062	$0.06056	$0.06067	$0.06426	$0.06820	$0.06895	$0.06405	$0.06710	$0.07360	$0.07703	$0.06608
14	MOHAVE	$0.07110	$0.05854	$0.05982	$0.05888	$0.05863	$0.05942	$0.06217	$0.06693	$0.06488	$0.06723	$0.07128	$0.08005	$0.06391
15	SULPHER	$0.07036	$0.05813	$0.05969	$0.05895	$0.05866	$0.05914	$0.06113	$0.06335	$0.06067	$0.06155	$0.06381	$0.07387	$0.06230
16	TRICO	$0.07644	$0.06469	$0.06298	$0.06112	$0.06086	$0.06204	$0.06522	$0.06925	$0.06431	$0.06616	$0.07062	$0.08089	$0.06611
17	AEPCO CLASS A	$0.07223	$0.06016	$0.06081	$0.05969	$0.05946	$0.06043	$0.06297	$0.06629	$0.06301	$0.06475	$0.06823	$0.07755	$0.06406

Arizona Electric Power Cooperative, Inc.

CHANGES IN REPRESENTATIVE RATE SCHEDULES - Staff Adjusted

Line No.	RATE DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS
1	PRESENT MONTHLY CHARGES			
2	FIXED CHARGE	$855,113	$757,429	$14.980
3	O&M CHARGE	$7.260	$7.260	N/A
4	TOTAL FIXED CHARGE PLUS O&M CHARGE	$1,894,341	$1,743,462	$14.980
5	BASE ENERGY CHARGE	N/A	N/A	N/A
6	OTHER EXISTING RESOURCE ENERGY CHARGE	N/A	N/A	N/A
7	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	N/A
8	AVERAGE ENERGY CHARGE	$0.020730	$0.020730	$0.020730
9				
10	PROPOSED MONTHLY CHARGES			
11	FIXED CHARGE	$764,975	$677,366	$931,105
12	O&M CHARGE	$1,274,882	$1,128,876	$1,178,484
13	TOTAL FIXED CHARGE PLUS O&M CHARGE	$2,039,858	$1,806,243	$2,109,589
14	BASE ENERGY CHARGE	$0.032147	$0.032285	$0.032345
15	OTHER EXISTING RESOURCE ENERGY CHARGE	$0.068787	$0.066755	$0.067461
16	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	$0.067461
17	AVERAGE ENERGY CHARGE	$0.035943	$0.036711	$0.037211
18				
19	CHANGE IN MONTHLY CHARGES			
20	FIXED CHARGE	($90,138)	($80,063)	N/A
21	O&M CHARGE	$235,655	$142,844	N/A
22	TOTAL FIXED CHARGE PLUS O&M CHARGE	$145,517	$62,781	N/A
23	BASE ENERGY CHARGE	N/A	N/A	N/A
24	OTHER EXISTING RESOURCE ENERGY CHARGE	N/A	N/A	N/A
25	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	N/A
26	AVERAGE ENERGY CHARGE	$0.015213	$0.015981	$0.016481

Arizona Electric Power Cooperative, Inc.

TYPICAL BILL ANALYSIS

THIS SCHEDULE IS NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

BILL COUNT

THIS SCHEDULE IS NOT APPLICABLE

Exhibit D

Arizona Electric Power Cooperative, Inc.
Summary of Revised Proposed Rates
TRICO PRM Case
Docket No. E-01773A-09-0472

	Proposed Rates Amended Filing - 4/20/2010 TRICO as ARM				Revised Proposed Rates TRICO as PRM			
All-Requirements Members:								
Fixed Charge		862,343	/Month (1)		$	232,978	/Month (1)	
O&M Charge		1,229,653	/Month (1)		$	436,144	/Month (1)	
Energy Rates:								
Base Resources	$	0.03236	/kWh		$	0.03157	/kWh	
Other Resources	$	0.06746	/kWh		$	0.06069	/kWh	
Energy Rate	$	0.03722	/kWh	(Average)	$	0.03276	/kWh	(Average)
Partial-Requirements Members:								
Mohave Electric Cooperative:								
Fixed Charge	$	709,721	/Month		$	709,721	/Month	
O&M Charge	$	1,323,724	/Month		$	1,323,724	/Month	
Energy Rates:								
Base Resources	$	0.03216	/kWh		$	0.03216	/kWh	
Other Existing Resources	$	0.06879	/kWh		$	0.06879	/kWh	
Energy Rate	$	0.03595	/kWh	(Average)	$	0.03595	/kWh	(Average)
Sulphur Springs Valley Electric Cooperative:								
Fixed Charge	$	628,440	/Month		$	628,440	/Month	
O&M Charge	$	1,172,125	/Month		$	1,172,125	/Month	
Energy Rates:								
Base Resources	$	0.03230	/kWh		$	0.03230	/kWh	
Other Existing Resources	$	0.06676	/kWh		$	0.06676	/kWh	
Energy Rate	$	0.03672	/kWh	(Average)	$	0.03672	/kWh	(Average)
Trico Electric Cooperative:								
Fixed Charge	(Rates as stated above for				$	629,365	/Month	
O&M Charge	All-Requirements Members)				$	793,509	/Month	
Energy Rates:								
Base Resources					$	0.03240	/kWh	
Other Existing Resources					$	0.06612	/kWh	
Energy Rate					$	0.03885	/kWh	(Average)

(1) The Fixed Charge and the O&M Charge will be apportioned among the ARMs and allocated to each ARM based upon each ARM's monthly Demand Share Ratio. The Demand Share Ratio will be calculated each month as the percentage of each ARM's 12-month rolling average demand to the total of the ARMs' 12-month rolling average demand.

EXHIBIT
S-4
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

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-01773A-09-0472

(REDACTED)

DIRECT

TESTIMONY

(PRUDENCE REVIEW)

OF

JOHN ANTONUK

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 30, 2010

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EXHIBIT

Resume JEA-1

INTRODUCTION

Q State your name, position, and business address.

A. My name is John Antonuk. I am president of The Liberty Consulting Group ("Liberty"). My business address is: The Liberty Consulting Group, 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Mr. Antonuk, briefly summarize your education background and professional qualifications as they relate to the subject of your testimony.

A. I began my career in service with the Commonwealth of Pennsylvania, first as an investigator with the Attorney General's Office (investigating major issues in pending civil litigation cases involving that office), and then as Assistant Counsel to the Pennsylvania Public Utilities Commission. Then, for several years, I headed a group in the Regulatory Affairs Department of Pennsylvania Power & Light Company (now PPL). After serving for a number of years as the head of the litigation consulting practice for a major west coast management consulting firm, I was one of the founders of Liberty, which is now approaching a quarter century of service. I have managed or provided executive direction in two hundred or more Liberty projects, working in virtually every State and serving two-thirds of the State utility regulatory authorities in the United States. My work has involved investor-owned, cooperative, public authority and municipally-owned electricity, natural gas, and telecommunications utilities. I have led or conducted work involving nearly every facet of utility governance, management, operations, finance, rate and regulatory, and corporate support.

Addressing energy utility fuel and energy management and operations performance has been an area of particular emphasis for me, not only in my assignments with Liberty, but also in my tenure with the public utility commission and a major electric utility in Pennsylvania.

My work in fuel procurement and management began in the immediate aftermath of the first Mideast oil embargo in the early 1970s; it has continued throughout many engagements across my time with Liberty.

I am an honors graduate of Dickinson College and the Dickinson School of Law.

Q. Have you prepared a more detailed summary of your background?

A. Yes; it is contained in Exhibit JEA-1 provides it.

Q. What is the purpose of your testimony?

A. Liberty performed under my overall direction: (a) an examination of the prudence of fuel, purchased power, and plant operations policies, activities, and costs of Arizona Electric Power Cooperative, Inc. ("AEPCO" or "the Cooperative"), and (b) an engineering review of AEPCO's facilities. Liberty prepared a report addressing the findings, conclusions, and recommendations of that examination. It is attached to my testimony as Exhibit JEA-2. While the entire report was prepared under my direct supervision; Randall Vickroy is appearing as a witness to address questions about the portions of Exhibit JEA-2 addressing Power Transactions (Chapter VI) and Richard Mazzini is appearing as a witness to address questions about the portions of Exhibit JEA-2 addressing Engineering Analysis/Plant Operations (Chapter VII). They had direct responsibility for conducting the activities which underlie the conclusions and recommendations described in those chapters.

Q. What was the scope of the Liberty review described in Exhibit JEA-2?

A. Liberty addressed the following 18 areas that were identified by Staff in the Request for Proposals that set the scope for the examination that Liberty performed:

- Overall fuel and purchased power procurement policy, goals, and strategies
- Organization and decision making structure
- Fuel and purchased power procurement policies and procedures
- Fuel and purchased power costs (test year and historical)
- Plant availability and capacity factor data and trends
- On-site inspection of major Apache Station Generation Plant facilities
- Modeling to develop forecasts of fuel and purchased power requirements
- Dispatch modeling and effectiveness
- Fuel and purchased power contracts and compliance with terms and conditions
- Hedging
- Off-system sales
- AEPCO audits of fuel procurement and purchased power
- Historical fuel and purchased power prices
- Sample review of contract entry and administration processes and activities
- Calculation of base cost of fuel and purchased power
- FPPAC historical performance and continuation
- Potential FPPAC modification
- FPPAC Plan of Administration changes.

Liberty divided the work required by these 18 specific scope items into the following overall areas:

- Organization, Staffing, and Controls
- Fuel Contracting
- Fuel Supply Management
- Gas Hedging
- Power Transactions
- Engineering Analysis/Plant Operations
- FPPAC.

Q. Please summarize what Liberty concluded in the area of organization, staffing, and controls?

A. In my opinion AEPCO's fuel and energy management division is organized appropriately and it includes capable individuals. All personnel involved in fuel and energy procurement and management activities operate under appropriate job descriptions. An appropriate set of procedures, policies, guidelines, approval authorities, and trading controls address technical and ethical performance. AEPCO has made effective use of ACES Power Marketing to provide a range of capabilities and services that are generally difficult for relatively smaller organizations to replicate. One area requiring improvement is in the conduct of internal audits regarding fuel and energy procurement and management. The magnitude of fuel and purchased power costs and the risks they pose in any organization like AEPCO's calls for more frequent and robust examinations of costs and performance.

Q. Please summarize Liberty's conclusions in the area of fuel contracting.

A. AEPCO's fuel procurement has been supported by reasonable consumption forecasts. There has, however, been a recent increase in inventory due to less availability of the two Apache steam units. Procurements have considered an appropriate range of alternatives, included proper analysis of those alternatives, properly considered the potential for significant changes in freight rates, and produced sufficient justification and approval documentation. AEPCO has pursued coal resales and swaps, which have produced savings for members, permitted opportunity for testing new sources of supply, and mitigated the effects of increased rail costs. The Cooperative's actions in these cases are commendable. AEPCO has also taken appropriate action to contest proposed increases in rail transportation rates from the Union Pacific.

AEPCO has also appropriately developed, and is properly maintaining its gas-supply relationships. The Cooperative uses appropriate standard agreements, operates a proper transaction recording and tracking system, makes effective use of ACES Power Marketing (an enterprise established initially by a group of cooperative G&Ts) and has established effective transportation and storage arrangements and agreements.

AEPCO makes its forward purchases from [redacted] major suppliers: [redacted] Liberty believes, however, that AEPCO should solicit interest from other suppliers, as a means of assuring that its traditional sources continue to offer the best available terms in a dynamic marketplace. AEPCO's forward purchases amount to [redacted], even under current, depressed market prices. This level of business should be sufficient to induce interest from other suppliers who may be in a position to serve AEPCO's needs. Liberty does not predict that this effort will reduce costs, but believes it will verify that best costs continue to be obtained.

Liberty's review of gas contract decisions demonstrated sound analysis, appropriate documentation, and proper approvals.

Q. Please summarize your recommendations with respect to fuel contracting.

A. Liberty recommended that AEPCO's future solicitations for forward gas purchases solicit interest from additional suppliers beyond its traditional sources for AEPCO's forward gas purchases.

Q. Please summarize what Liberty concluded in the area of fuel supply management.

A. AEPCO applies appropriate processes and procedures for the weighing, sampling, and analysis of coal shipments to Apache. AEPCO's coal contracts make provisions sufficient to support these activities. AEPCO independently analyzes samples at reasonable intervals, and has observed no unusual trends. Variations between physically-measured and book coal inventory values have historically fallen into a normal range, but recently, the majority have consisted of physical measurements that are less than book values. The lack or randomness in variations merits examination.

AEPCO has effectively administered its coal contracts to assure quantity and quality control, while appropriately maintaining effective supplier relationships. AEPCO has taken steps to monitor quality and assess applicable adjustments for quality deviations. AEPCO has effectively communicated internally on all aspects of coal scheduling and deliveries.

AEPCO decided to increase certain coal inventories, in order to address the prospect of substantially increased coal transportation rates. This decision was effective; AEPCO supported it with appropriate economic analysis.

Inventories continued to build even beyond increased expectations under this decision. That increase, however, resulted from external circumstances (subsequently reduced Apache availability) that did not reflect on the soundness of the strategy. Nevertheless, AEPCO coal inventories have now reached levels that should be considered unacceptable. An inventory level of approximately 75 days would conform to the increased stockpile strategy. The 137-day level reached as of the end of 2009 has become too high; AEPCO needs to develop a strategy to address the situation.

Liberty also found gas-supply management to be generally effective. AEPCO has sufficient and not excessive resources (e.g., power-purchase contracts, generating units, fuel-purchase arrangements). Liberty also observed effective management practices and mechanisms for managing gas supply. Liberty did not, however, find significant efforts to measure results. AEPCO needs to explore the creation of specific performance measurement for gas traders to improve performance measurement and inducement.

Q. With respect to fuel supply management, please summarize the recommended actions on AEPCO's part to address your concerns.

A. We made three recommendations. First, AEPCO should undertake a formal process for examining the causes of differences between physical and book inventory, and take corrective action, as appropriate. Second, AEPCO should develop a plan for reducing the coal inventory level at the Apache Station. Third, AEPCO should explore the creation of a set of specific performance measures for its traders

Q. Please summarize what Liberty concluded in the area of gas hedging.

A. AEPCO's objective for its gas hedging program is [redacted] Liberty understands that the member cooperatives, through their representatives to AEPCO's Board of Directors, understand and support this objective, which is certainly an appropriate one. AEPCO does not, however, formally assess its effectiveness in meeting this objective. At a minimum, AEPCO should conduct annual assessments to determine whether the hedging program is meeting its stated objective: [redacted] Many utilities also use assessments of their hedging program to try to improve performance.

In pursuing its hedging objective, AEPCO applies effective strategies, and uses appropriate instruments. The Cooperative uses [redacted]. Hedging personnel are adequately qualified and AEPCO makes effective use of ACES Power Marketing to support hedging activities.

AEPCO applies appropriate risk-management policies and procedures. They address hedging for electric power and for natural gas. These policies and procedures cover all important areas, and are soundly constructed. AEPCO's transaction-tracking capabilities and systems are also strong. AEPCO has not, however, subjected trading to regular audits. Liberty found no indication of improper activity here, but both our examinations at other enterprises and industry experience generally confirm that trading is a high-risk, high-consequence area of operation. Therefore, good practice, regardless of the lack of a history of problems, requires periodic testing of controls on trading.

Q. Please summarize your recommendation with respect to AEPCO's gas hedging program?

A. We made two recommendations. First, AEPCO should adopt a program that will provide for measurement of hedging program results. Second, the Internal Audit group at AEPCO should periodically review the processes and systems for tracking of transactions.

Q. Please summarize what Liberty concluded in the area of power transactions.

A. AEPCO effectively manages the scheduling, real-time dispatch, and trading functions associated with making power purchases and sales. There exist clear lines of

responsibility, established operating routines, and a qualified work force. AEPCO regularly takes advantage of hourly market opportunities to purchase power when it will displace more costly internal sources. Day-ahead and real-time operations effectively use market information. AEPCO's large members, however, fail to provide to AEPCO on a timely basis the pre-scheduling information that AEPCO needs to produce its daily, day-ahead schedule. Potentially wide swings in what these members expect AEPCO to schedule can thus produce significant daily over- or under-supply. AEPCO schedulers have to make their "best estimate" of the pre-schedules of these large members in order to provide AEPCO's schedule to the Inter-Continental exchange ("ICE"). AEPCO needs to require more timely submissions from the members involved, and evaluate if any past harm may have resulted to AEPCO and other members from the lack of timely information.

AEPCO's power trading operations have established effective processes and methods for arranging economic term purchases of power. The Cooperative has primarily arranged power trades on an hourly, real-time basis, and also under its long-term contracts, using market power information effectively to analyze opportunities. AEPCO's processes for soliciting long-term power resources have been thorough and effective. AEPCO has solicited proposals for power supply resources several times since 2001, using solicitation processes that Liberty found to be thorough and robust. AEPCO has taken advantage of overbuilt power supply markets in the Southwest region to benefit its members. AEPCO's information gathering and analysis demonstrated its purchases to have been superior at the time to self build and other purchase options. AEPCO has appropriately decided to join in Southwest Public Power Resources power supply solicitations since 2006, recognizing that its future needs for power supply resources will be much smaller (89 percent of AEPCO's future member load will be for partial requirements customers).

AEPCO's internal audit reports show an insufficient attention to detail regarding the fuel and purchased power adjustment clause ("FPPAC"), which the Cooperative has only recently resolved. AEPCO also lacks written processes and procedures for calculating and reconciling information and reports. Significant AEPCO changes to its processes that resulted from the internal audit report should minimize or eliminate the errors experienced in 2007 and 2008. AEPCO's schedule for completing written procedures, however, (mid-2011) needs to be accelerated. Moreover, upon completion of the process documentation, AEPCO should demonstrate to the Commission that its changes do in fact address all causes of its past errors and that it is taking continuing actions, including frequent internal audits, to verify their sufficiency.

Q. Please summarize your recommendations related to AEPCO's power transactions?

A. We made two recommendations. First, AEPCO should require its partial requirements members and Salt River Project ("SRP") to make timely submissions of pre-scheduling power requirements. Second, AEPCO should undertake a series of steps to assure the Commission that it has effectively completed, can demonstrate, and will periodically audit the effectiveness of the new adjustment clause processes.

Q. Please summarize what Liberty concluded in the area of engineering analysis/plant operations.

A. Technical performance, personnel and facilities are generally sound, and AEPCO's management team is capable, knowledgeable, and supported with appropriate tools. AEPCO's power plant operations are generally appropriate and typical of the industry, AEPCO's investment in new and upgraded facilities has been appropriate for the demands placed on the Cooperative, and maintenance practices and spending appear to be consistent with the station's needs and good utility practice. However, despite reasonably

effective performance historically, AEPCO faces significant questions about the future of its units. Apache Steam Units 2 and 3, the coal-fired units that currently produce more than 95 percent of the station's output, have operated in a base-load mode for about 30 years, but now appear more likely to cycle. This change has resulted from a decline in the units' market competitiveness. Increased unit cycling may be having impacts on equipment, contributing to a significant drop in availability in 2009. Management needs to examine the potential for continuing lower station output which, if it continues, suggests a limited future for these units. The key question at this time is whether 2009 conditions are anomalous or a warning of continuing deterioration.

As to AEPCO's other generation sources, first, Steam Unit 1 ("ST1"), a gas-fired boiler that operates in combined cycle with gas turbine 1 ("CC1"), also had low 2009 availability, but AEPCO has addressed unit needs and has completed an analysis that justifies further investment in ST1 (the boiler re-tube). Management's recent study of future options concluded that continued use of CC1 for reserve and seasonal peaking capacity remained AEPCO's most economic alternative. If AEPCO can succeed in: (a) stabilizing availability at high levels going forward, and (b) holding maintenance costs at reasonable levels, it would appear that continued operation of the unit makes sense. The three gas turbines are peaking units; they have had good availability over time. Deviations in performance give no reason to conclude that operating problems have arisen or that they will not remain useful to AEPCO.

Liberty's review of maintenance found that AEPCO employs good practices in preparing for and managing outages. However, the Cooperative's consistent overruns in outage durations is not typical, and warrants a structured examination and the adoption of a more formal and structured approach that would nevertheless remain consistent with the

comparatively small size of AEPCO's fleet. Spending on maintenance has generally been consistent for many years. There were some years of comparatively lower spending in the late 1990s, but Liberty found no reason to conclude that any spending reductions have had a material impact on plant performance.

Liberty found that the Apache station suffers a particularly high number of trips due to personnel errors. The numbers are high enough to warrant root cause analysis of these trips. AEPCO has not suffered significant cost penalties due to forced outages. The 13 forced outages of 2008 and 2009 combined have caused AEPCO to experience total replacement costs less fuel costs of [redacted] million. Fuel and purchased power expenses in these two years are in the range of $140 million.

AEPCO's recent investments in plant have been justified and appropriate. The review underlying this conclusion included all of the capital project justifications for large projects. Liberty found them to be in order and supportive of management's decision-making needs. Liberty found the listing of projects typical for coal-fired units of this age. Liberty reviewed the justification for each of the listed projects as documented on the "Capital Project Analysis" sheets, and found all to be reasonable. In summary, historical capital and O&M spending appears to have been appropriate; however, questions should be raised concerning future spending. Actual and forecasted spending from 2008 to 2014 is more than double the annual levels between 2004 and 2007. Considering the uncertainties on the future role of the station as discussed above, the appropriateness of a much higher and sustained level of capital investment in the future is not clear.

Q. Please summarize your recommendations in the area of engineering analysis/plant operations.

A. Liberty made three recommendations. First, AEPCO should conduct a study of the future role of Apache and how that role relates to member needs for future power supply. Second, AEPCO should examine methods to create more structured and formal outage planning and management. Third, AEPCO should examine the root causes of trips resulting from personnel errors.

Q. Please summarize what Liberty concluded about the FPPAC.

A. AEPCO's FPPAC, approved in 2005, and changed in 2008 to accelerate the recovery of a growing under collection balance has served to mitigate the effects of over and under collections of fuel and purchased power costs. Some states have taken a different approach to adjustor clause design; *e.g.*, using forecasted rather than historical costs, and using shorter periods to recover or refund under or over collected balances. The Commission expressed concern about balances in the range of $5 million in shortening the balance-recovery period to six months. Current market indications create the very real possibility that AEPCO balances could rise to or above that level in the future, although the balance has been dropping steadily through a period of depressed energy prices. It is therefore appropriate to consider a further shortening of the balance-recovery period, but that consideration should take place in a manner that allows the members to consider what corresponding changes they may need to make in the means for recovering costs from their members at the end-use level.

For reasons particular to AEPCO's circumstances, Liberty does not recommend the use of forecasted costs for setting an FPPAC rate or the inclusion of the costs and revenues from transactions in SO2 allowances.

Liberty found appropriate AEPCO's proposed FPPAC change whose purpose is to align amounts recovered from individual members more closely with the hourly costs they impose on AEPCO. Should the Commission approve this modification, editorial revision of AEPCO's proposed Plan for Administration of the FPPAC should take place through a joint Staff/AEPCO process. In the event of acceptance of the proposed FPPAC change, AEPCO should also provide for a temporary surcharge intended to recover balances accrued under the current FPPAC (up to the date of the new FPPAC effectiveness) and to provide for that recovery through a mechanism that essentially continues the same balance recovery methods that apply under the current FPPAC.

Q. Please summarize your recommendations with respect to the FPPAC.

A. Liberty made two recommendations. First, AEPCO should address through focused discussions with the Class A members the means for introducing in an orderly fashion a change that will produce more current FPPAC recovery. Second, assuming that AEPCO's proposed FPPAC continuation and changes are found by the Commission to be generally appropriate, the Cooperative needs to establish a temporary surcharge mechanism, and clarify the proposed plan for administering it. The most direct means for closing out old FPPAC balances would be to continue the Bank Account feature of the current clause.

Q. Should the FPPAC continue?

A. Yes, for the reasons discussed in the FPPAC chapter of Liberty's report attached as an exhibit to this testimony.

Q. Does that conclude your Direct Testimony?

A. Yes.

John Antonuk Resume

Areas of Specialization

Executive management; management audits and assessments; service quality and reliability management and measurement, utility planning and operations; litigation strategy; management of legal departments; human resources; risk management; regulatory relations; affiliate transactions and relations; subsidiary operations; and testimony development and witness preparation.

Relevant Experience

Electricity

Project Manager and lead consultant on Liberty's management and operations audit of the electricity, natural gas, and steam operations of ConEd for the New York Public Service Commission.

Project Manager for Liberty's audit of the fuel and purchased-power procurement practices and costs of Arizona Public Service Company for the Arizona Corporation Commission. Liberty completed audits relating to fuel procurement and management and on rate and regulatory accounting for related costs at Arizona Public Service Company for the Arizona Corporation Commission. The fuel and purchased power audit included extensive reviews of all physical and financial transactions of both the utility and a wholesale marketing affiliate, including the relationship between the two entities.

Project Manager for Liberty's audit of Duke Energy Carolinas for the North Carolina Utilities Commission. Scope included compliance with regulatory conditions and code of conduct imposed by the Commission after the merger with Cinergy, and affiliate transactions and cost allocation methods.

Project Manager for Liberty's audit of affiliate transactions of Nova Scotia Power on behalf of the Nova Scotia Utility and Review Board.

Project Manager for Liberty's audit for the New Jersey Board of Public Utilities of the competitive service offerings of the state's four major electric companies. Scope included corporate structure, governance, and separation, service company operations and charges, inter-affiliate cost allocations, arm's-length dealing with respect to a variety of code-of-conduct requirements, and protection of customer and competitor proprietary information.

Project Manager and witness for the staff of the Arizona Corporation Commission addressing the merits of the proposed acquisition of UniSource by a group of private investors.

Project Manager and witness before the Oregon Public Utility Commission addressing the merits of the proposed acquisition of Portland General Electric by a group of private investors.

Engagement Director for Liberty's provision of engineering and technical assistance to the Vermont Public Service Board in connection with review of public necessity and convenience related to the Northwest Reliability Project, which would add a major new 345kV transmission plan to provide an additional source of electricity to serve Vermont's major load growth in its northwest region. The project involved transmission reinforcements at lower voltages and significant substation upgrade work. The proceedings had numerous public, private, and government interveners, who raised issues regarding project need, available electrical alternatives, routing and design, and electromagnetic radiation.

Project Manager for Liberty's support for the New Hampshire Public Utilities Commission in its charge to oversee the divestiture of the Seabrook nuclear plant as part of a major restructuring settlement. The sale produced record high compensation for nuclear facilities in the country.

Project Manager and witness for Liberty's assessment of fuel procurement, affiliate transactions, and automatic adjustment clause implementation for the staff of the Nova Scotia Utility and Review Board in rate case of Nova Scotia Power.

Project Manager for Liberty's engagement on behalf of Boston Edison to examine the company's affiliate relations, including issues of the valuation of assets transferred to an affiliate. Testified in proceedings before the Massachusetts Department of Telecommunications and Energy (formerly the Department of Public Utilities) on several telecommunications issues, including: (a) development of competition, and legislative and regulatory-policy changes supporting it, (b) electric-utility entry into telecommunications markets, (c) costs, prices, and market value of network elements, (d) requirements of the Telecommunications Act of 1996, (e) assessment of compliance with commission orders, company procedures, and service agreements regarding limits on affiliate interactions, (f) inter-company loans, guarantees, and credit support among utilities and their affiliates, (g) accounting for affiliate transactions, (h) obligations to allow nondiscriminatory access to network infrastructure to third parties, and (i) cost pools, overhead factors, and allocation of common costs among utility and non-utility affiliate activities and entities.

Project Manager for Liberty's major consulting engagement for the New Hampshire Public Utilities Commission. Liberty examined management, operations, and costs at Public Service Company of New Hampshire/Northeast Utilities, which is engaged in the operational and cost-accounting separation of its network into segments, for the purposes of restructuring service offerings to allow competition in certain aspects of electric-energy supply. This engagement included an assessment of valuations of nuclear and fossil units, as well as supply contracts with independent-power producers. Liberty also assisted in efforts to settle rate case and restructuring

disputes involving, among other issues, stranded costs associated with power plants. The scope of Liberty's work included the development of plans and protocols for power plant (fossil, hydro, and nuclear) and power supply contract assets, as well as the oversight of activities associated with asset auctions.

Engagement Director for Liberty's evaluation of corporate relations and affiliate arrangements of Dominion Resources, Inc. and Virginia Power for the Virginia State Corporation Commission. This project addressed all significant aspects of corporate governance, operating relationships, and affiliate arrangements between the two entities.

Project Director for Liberty's evaluation of a report prepared by a consultant to the Hawaii Public Utilities Commission on the relationship between Hawaiian Electric Industries (HEI), a diversified utility-holding company, and Hawaiian Electric Company (HECO), its principal subsidiary and operating electric utility.

Project Director for all aspects of Liberty's comprehensive management and operations audit of West Penn Power Company for the Pennsylvania Public Utility Commission (PAPUC). Managed focused reviews of the Company's affiliated costs, power dispatch and bulk power transactions, customer services, finance, and corporate services. Presented testimony before the PAPUC on behalf of the Office of Trial Staff regarding the results of the audit in West Penn's rate case.

Lead Consultant for affiliate relations for Liberty's assignment of providing assistance to Delmarva Power & Light Company in developing and implementing self-assessment and continuous-improvement processes.

Project Director for Liberty's reviews of fossil-fuel procurement and administration in Liberty's management/performance audits of the Centerior Energy Company's operating companies- Cleveland Electric Illuminating Company and Toledo Edison Company- and Ohio Edison, Monongahela Power (an Allegheny Power System operating company), and Cincinnati Gas & Electric, for the Public Utilities Commission of Ohio.

Served as advisor to the administrative law judge of the Delaware PSC responsible for hearing cases regarding the implementation of the new law that restructures the electric-utility industry in Delaware.

Engagement Director for nuclear-plant performance-improvement projects that Liberty conducted for Duquesne Light Company, Centerior Energy, Nebraska Public Power District, and Pennsylvania Power & Light Company (PP&L).

Engagement Director for a Liberty assignment for Florida Power Corporation, regarding a proposal by the Tampa Electric Company to construct transmission lines to serve the cities of Wauchula and Fort Meade, Florida. Liberty's testimony helped convince the Florida Public Service Commission that Tampa Electric Company's proposed line was uneconomic.

Directed Liberty's engagement to assist a regional electric generation and transmission cooperative, whose members' combined operations make it a major competitor in the state's electricity business, to conduct its first-ever comprehensive and formal strategic-planning process.

Natural Gas

Project Manager for Liberty's examination of safety programs and activities of NiSource's Maine subsidiary Northern Utilities for the Maine Public Service Commission.

Project Manager for Liberty's focused and general management audits of NJR, New Jersey Natural Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues. Personally performed the reviews of governance, EDECA requirements compliance, and legal services.

Project Manager on a major focused audit of Peoples Gas/Integrys that Liberty performed for the Illinois Commerce Commission. Audit topics included natural gas forecasting, portfolio design and implementation, gas purchase and sale transactions, controls, organization and staffing, asset management, off-system sales, storage optimization, and all other issues related to gas supply over a period of eight years.

Project Manager and witness on three recent audits of fuel (primarily coal and natural gas) procurement and management practices of Nova Scotia Power, a review of the merits and mechanics of a company-proposed automatic recovery method for energy costs, and an audit of affiliate relationships (including coal, electric power, and natural gas procurement activities) performed for the Nova Scotia Utility and Review Board.

Project Manager for Liberty's focused and general management audits of SJI, South Jersey Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues. Personally performed the reviews of governance, EDECA requirements compliance, and legal services.

Project Manager for Liberty's work with staff of the Virginia State Corporation Commission to evaluate the services of an affiliate providing gas portfolio management services under an asset management agreement with Virginia Natural Gas, an operating utility subsidiary of Atlanta-based AGLR.

Project Manager for Liberty's focused audit of NUI Corporation and NUI Utilities. This audit included a detailed examination of the reasons for poor financial performance of non-utility operations, downgrades of utility credit beneath investment grade, and retail and wholesale gas supply and trading operations. Also examined performance of telecommunications, engineering services, customer-information-system, environmental, and international affiliates. The audit included detailed examinations of financial results, sources and uses of funds, accounting systems and controls, credit intertwining, cash commingling, and affiliate transactions, among others. Liberty's examination included very detailed, transaction-level analyses of commodities trading undertaken by a utility affiliate both for its own account and for that of utility operations.

Project Manager for Liberty's comprehensive management audit of United Cities Gas Company for the Tennessee Public Service Commission. Responsible for the focused reviews of affiliate interests, executive management and corporate planning, and vehicle management.

Lead Consultant in Liberty's management audit of Connecticut Natural Gas Company for the Connecticut Department of Public Utility Control (DPUC). Responsible for reviews of organization and executive management and legal management.

Lead Consultant in Liberty's management audit of Southern Connecticut Gas Company for the DPUC. Responsible for organization and executive management, affiliates, and legal management. Included valuation of a major, rate-based LNG facility being offered for sale.

Directed Liberty's management audit of Yankee Gas Services Company for the DPUC.

Engagement Director for Liberty's evaluation of regulatory needs and alternatives for the Georgia Public Service Commission in regulating the state's local-gas-distribution companies in the aftermath of FERC Order 636.

Project Director for Liberty's review of gas-purchasing policies and practices at Pike Natural Gas Company and Eastern Natural Gas Company for the Public Utilities Commission of Ohio. Responsible for the review of organization and staffing and regulatory-management issues.

Combination Utilities

Engagement Director for Liberty's examination of the cost-allocation methods of Baltimore Gas & Electric Company and its affiliates for the Maryland Office of People's Counsel.

Project Director for Liberty's focused management audit of affiliate transactions of Public Service Electric & Gas Company (PSE&G) and the unregulated subsidiaries of Public Service Enterprise Group, Inc., the parent, for the New Jersey Board of Regulatory Commissioners. Task leader for the review of organization and planning, and executive management.

Project Director for Liberty's management and operations audit of New York State Electric & Gas Corporation for the New York Public Service Commission (NYPSC). Responsible for managing the review of corporate planning and organization, service centralization, specific corporate services, and finance and accounting.

Project Director for Liberty's management and operations audit of Central Hudson Gas & Electric Corporation for the NYPSC.

Telecommunications

Arbitrator named by the District of Columbia Public Service Commission to address industry-wide need for amendments to interconnection agreements as a result of the FCC's Triennial Review Order.

Project Manager for assistance being provided to the Administrative Law Judge of the Delaware Public Service Commission hearing the arbitration to address industry-wide need for amendments to interconnection agreements as a result of the FCC's Triennial Review Order.

Project Manager for Liberty's engagement to serve as advisors to commissioners of the District of Columbia Public Service Commission in their review of the Section 271 application of Verizon to provide in-region, interLATA service in the District.

Project Manager for Liberty's engagement to serve as advisor to the administrative law judge of the Delaware Public Service Commission in the review of the Section 271 application of Verizon to provide in-region, interLATA service in the state.

Retained by the Idaho PUC to serve as administrative law judge in complaint proceedings involving three paging companies and Qwest, involving a variety of financial disputes arising out of interconnection and tariff purchases.

Conducted wholesale performance metrics training for staff members and commissioners of the Pennsylvania Public Utility Commission as part of efforts to monitor service quality and payments under the Verizon Performance Assurance Plan adopted in connection with the RBOC's entry into the in-region inter-LATA market in Pennsylvania.

Engagement Director for Liberty's comprehensive financial review of Verizon New Jersey Inc. *(VNJ)* for the New Jersey Board of Public Utilities. The review had three parts: a financial evaluation; a review of merger costs and savings; and an assessment of affiliate costs and transactions.

Engagement Director for Liberty's audit of Ameritech-Ohio policies, procedures and compliance with service quality performance requirements under Ohio's Minimum Telephone Service Standards.

Engagement Director for Liberty's audit of Qwest's performance measures for the Regional Oversight Committee *(ROC)*. Responsible for the evaluation of the processes and data tracking of several hundred wholesale and retail performance indicators including service areas such as provisioning, OSS access, maintenance and repair, and billing.

Project Manager and hearing administrator for Qwest's 271 hearings for the commissions of Idaho, Iowa, Montana, New Mexico, North Dakota, Utah, and Wyoming.

Engagement Director for Liberty's assistance provided to the Staffs of the Virginia State Corporation Commission and the New Jersey Board of Public Utilities in the implementation of the 1996 Telecommunications Act.

Project Manager for Liberty's assistance to Delaware PSC arbitrators in seven different interconnection cases arising out of the Telecommunications Act.

Served on an arbitration board in Mississippi, and as the sole arbitrator in two cases in Idaho regarding interconnection agreements between incumbent local-exchange companies and new entrants to the local telephone market.

Engagement Director for Liberty's work determining permanent prices for the unbundled-network elements of Southwestern Bell Telephone for the Oklahoma Corporation Commission.

Engagement Director for Liberty's provision of arbitration services to the North Dakota Public Service Commission and Nebraska Public Service Commission in cases involving implementation of the Telecommunications Act of 1996.

Engagement Director for Liberty's combined comprehensive management/affiliate-relations audit of Bell Atlantic - Pennsylvania for the PAPUC, and affiliate relations audit of Bell Atlantic - District of Columbia for the Public Service Commission (DCPSC) of the District of Columbia. Served as team leader with responsibility for the coordination of the review of executive management, finance, and support services.

Engagement Director for Liberty's examination of the accounting and allocation on lobbying costs of Bell Atlantic for an 8-year period for the DCPSC. Engagement included an examination of the propriety of policies and procedures for assigning and allocating lobbying costs.

Engagement Director for a management audit of GTE South, Inc. for the Kentucky Public Service Commission. This examination included a review of GTE's affiliate transactions.

Project Director for Liberty's evaluation of New York Telephone's transactions with affiliates for the NYPSC. Responsible for the review of affiliates involved in directories publishing, government affairs, international activities, information services, and the legal-affairs entity.

Project Director for Liberty's management audit of the affiliated interests of C&P Telephone of Maryland performed on behalf of the Maryland Public Service Commission.

Engagement Director for Liberty's two assignments for the DCPSC in reviewing Bell Atlantic - District of Columbia's construction-program planning and quality-of-service standards.

Other Companies

Set up and managed service and facilities section of the PP&L Regulatory Affairs Department. Counseled utility management on regulatory and legislative matters. Litigated rate related and facility construction proceedings before agencies and the courts.

Attorney for the PAPUC. Assigned as counsel to the Commission's Audit Bureau in developing a comprehensive management-audit system. Negotiated contracts for the first commission-ordered management audits in Pennsylvania. Revised Commission organization and practice to conform to regulatory-reform legislation.

Testimony

Nova Scotia Utility and Review Board – testimony on the prudence of fuel procurement, affiliate relationships associated with fuel management, and use of an automatic adjustment clause to recover fuel costs.

Arizona Corporation Commission – testimony on the merits and conditions of the proposed acquisition of UniSource by private investors.

Oregon Public Utility Commission – testimony on the merits and conditions of the proposed acquisition of Portland General Electric by private investors.

Virginia State Corporation Commission - testimony in arbitration cases regarding interconnection agreements between Bell Atlantic - VA and competing local exchange companies.

PAPUC - presentation of management-audit recommendations and benefits for selected conclusions in West Penn Power Company request for rate increase.

Maryland Public Service Commission - presentation and defense of management-audit conclusions, recommendations, and cost implications in C&P Telephone Company of Maryland (Bell Atlantic) rate case.

Illinois Commerce Commission - testimony about fuels organization, procurement, and management in fuel-cost reconciliation proceedings.

Maryland Public Service Commission - testified regarding Baltimore Gas & Electric Company's affiliate relations.

Tennessee Regulatory Authority - testified regarding Liberty's recommendations in a management audit of United Cities Gas Company.

Education

J.D., with academic honors, Dickinson School of Law
B.A., cum laude, Dickinson College

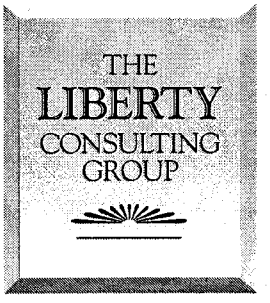
Public Report
Review of AEPCO Fuel, Purchased Power, Generation, and FPPAC Management, Operations, and Prudence

Shaded Portions are Confidential

Presented to the:

Arizona Corporation Commission

By:



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July 30, 2010

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I. Introduction

A. Background

The Liberty Consulting Group ("Liberty") conducted for the Staff of the Arizona Corporation Commission ("the Commission") an examination of fuel, purchased power, and plant operations policies, activities, and costs of Arizona Electric Power Cooperative, Inc. ("AEPCO" or "the Cooperative"), based in Benson, Arizona. AEPCO serves six Class "A" distribution cooperative members in the Southwest region:

- Graham County Electric Cooperative ("GCEC"); Pima, Arizona (8,904 meters)
- Sulphur Springs Valley Electric Cooperative ("SSVEC"); Willcox, Arizona (51,849 meters)
- Mohave Electric Cooperative ("Mohave"); Bullhead City, Arizona (43,042 meters)
- Trico Electric Cooperative ("Trico"); Marana, Arizona (38,811 meters)
- Duncan Valley Electric Cooperative ("DVEC"); Duncan, Arizona (2,375 meters)
- Anza Electric Cooperative ("ANZA"); Anza, California (4,962 meters).

AEPCO divides these members further into two classes:

- All-requirements members ("ARMs") who purchase all the requirements necessary for serving their distribution cooperative members: ***DVEC, GCEC, Trico, and ANZA***
- Partial-requirements members ("PRMs"), who purchase both from AEPCO and from other market sources: ***Mohave and SSVEC***.

AEPCO also has served some of the requirements of what it terms Class "B" and Class "D" members:[1]

- Salt River Project ("SRP"); Tempe, Arizona: will be a Class "B" member through December 31, 2010, when its firm 100 MW purchase from AEPCO will expire
- City of Mesa: ceased to be a Class "B" member upon the December 31, 2008 expiration of its 15 MW power and energy purchase from AEPCO
- Class "D" member Valley Electric Association ("VEA"); Pahrump, Nevada: Class "D" member through a service contract under which AEPCO provides scheduling and trading services.

There are no Class "C" members. AEPCO also made sales to the City of Mesa, Arizona, under a contract that expired on December 31, 2008. The accompanying table shows sales levels in the past two full years.

Category	2008 MWH	2009 MWH
Class A	2,346,706	2,201,798
Total	3,518,193	2,791,236

Liberty is a management, operations, technical, and regulatory consulting firm that specializes in the energy and telecommunications utility businesses. Liberty has served more than two-thirds of the country's utility regulatory authorities (and a number of others in North America) over a life that is approaching a quarter century. Liberty's work has included many examinations of electric utility fuel, power purchase, and power production management, operations, and prudence for regulators across the country. Liberty has also performed extensive work in the examination of

fuel and purchased power cost recovery through adjustment clauses, focusing on clause design, operation, and accuracy.

Liberty conducted this review in the context of an AEPCO rate filing before the Commission at Docket No. E-01773A-09-0472. AEPCO initially sought a modest increase in rates, and later revised its filing to call for a small decrease. AEPCO also seeks to change its Fuel and Purchased Power Adjustor Clause("FPPAC"), in order to segregate more fully the costs of power between its ARMs and PRMs.

B. Project Objectives and Scope

The objective of Liberty's review was to verify that AEPCO has acted prudently and reasonably in assuring cost and operational effectiveness in these areas. Liberty's examination included the following areas identified in the Request for Proposals ("RFP"):

1. Overall fuel and purchased power procurement policy, goals and strategies
2. Organization and decision making structure to and including the board of directors
3. Fuel and purchased power procurement policies and procedures and the potential for conflicts of interest
4. Fuel and purchased power costs during the test year and since FPPAC implementation
5. Plant operating availability, equivalent availability, and capacity factors and impacts of any observed declines
6. On-site inspection of the Apache Station Generation Plant, including fuel handling, quality control, inventory surveying methodologies and results, performance monitoring, and maintenance
7. Modeling used to develop forecasts of fuel and purchased power volume requirements
8. Dispatch modeling and effectiveness
9. Reasonableness of fuel and purchased power contracts and compliance with terms and conditions
10. Use of hedging
11. Test-year off-system sales
12. Audits (and management responses) of procurement of fuel and purchased power
13. Historical fuel and purchased power prices and comparison to industry data
14. Sample review of contract entry and administration
15. Calculation of base cost of fuel and purchased power to be used prospectively
16. FPPAC historical performance and continuation
17. Potential FPPAC modification
18. FPPAC Plan of Administration changes.

C. Task Structure

Liberty created the following task structure to facilitate its examination of the 18 included areas:

- Organization, Staffing, and Controls (Elements 1, 2, 3, 4 and 12)
- Fuel Contracting (Portion of Elements 9 and 14, Element 13)
- Fuel Management (the portion of Element 6 that deals with fuel-related matters)
- Gas Hedging (Element 10)
- Power Transactions (Elements 7, 8, 11, and portions of Element 9 and 14)
- Engineering Analysis/Plant Operations (Element 5 and remainder of Element 6)

- FPPAC Continuation/Amendment (Elements 16 through 18)

With respect to Element 15, the work in these areas disclosed no reason for adjusting claimed test-year fuel and purchased power expenses. Liberty therefore proposed no adjustment to them. They establish a base that is consistent with the vintage of other expenses. Moreover, as costs change in dynamic markets, continuation of the FPPAC will reconcile revenues and expenses over time.

D. Recent Financial Results

The following table summarizes and compares key AEPCO capital, revenue, and expense items for 2008 and 2009.[2]

AEPCO Capital and Expense Summary (2008 vs. 2009)

Capital Item	2009	2008	Change
Plant in Service	$429,448,020	$402,042,682	6.8%
CWIP	$9,354,610	$20,108,331	-53.5%
Depreciation	$212,515,354	$204,728,929	3.8%
Net Utility Plant	$226,287,276	$217,422,084	4.1%
Membership Capital	$84,514,994	$74,558,069	13.4%
Long-Term Debt	$ 177,094,771	$ 177,195,623	-0.1%
Revenue/Expense Item	**2009**	**2008**	**Change**
Class A Firm Sales	$121,129,138	$ 123,646,648	-2.0%
Class B Sales	$30,945,711	$ 42,938,769	-27.9%
Class D Sales	$995,289	$ 1,593,208	-37.5%
Underrecovery (fuel/power)	$46,434,309	$ 38,638,375	20.2%
Non-Member Sales	$9,054,338	$ 8,402,255	7.8%
Other Revenues	$593,432	$ 728,133	-18.5%
Total Operating Revenues	**$209,152,217**	**$ 215,947,388**	**-3.1%**
Fuel Expense	$79,520,400	$69,854,969	13.8%
Operations Expense	$8,824,265	$10,581,716	-16.6%
Maintenance Expense	$18,589,005	$15,322,190	21.3%
Purchased Power and Interchange	$38,386,804	$52,328,850	-26.6%
A&G	$11,595,386	$10,843,391	6.9%
Depreciation, amortization, accretion	$8,936,845	$8,054,263	11.0%
Transmission	$18,512,248	$18,526,791	-0.1%
Taxes	$2,879,532	$2,934,495	-1.9%
Total Operating Expense	**$187,244,485**	**$ 188,446,665**	**-0.6%**
Operating Margin	**$21,907,732**	**$ 27,500,723**	**-20.3%**
Interest and other	($11,950,807)	($10,144,953)	17.8%
Net Margin	***$9,956,925***	***$17,355,770***	***-42.6%***

E. Senior AEPCO Leadership

AEPCO was founded in 1961. Through a major restructuring in 2001, AEPCO was organized into three entities: 1) AEPCO, as a power supply organization; 2) Southwest Transmission Cooperative ("SWTC") as the transmission entity for serving the needs of member cooperatives; and 3) Sierra Southwest Cooperative Services ("Sierra"), which provides services and personnel for both AEPCO and SWTC. This structure was originally designed to match the changing requirements in the industry, in particular to position the enterprise to address market opening measures, which at the time looked to be emerging. The original allocation of personnel placed most staff at Sierra, but assigned staff directly to the other two entities to align with a RUS requirement that the CEO described as requiring each of the three entities to have intellectual capital.

AEPCO's most senior leadership consisted during the test year of the following directors and senior executives:

- Board Officers
  - President: Reuben B. McBride; Graham County Electric Cooperative
  - Vice President: Gene Robert Larson; Graham County Electric Cooperative
  - Secretary: Tom Powers; DVEC
  - Treasurer: George P. Davies; Trico
- Other Board Members
  - Gloria Britton; ANZA
  - Ryall Stewart; ANZA
  - Joe D. Croom; DVEC
  - Robert E.Broz; Mohave
  - Lyn R. Opalka; Mohave
  - Kathy Thatcher; SSVEC
  - Gene Manring; SSVEC
  - C. Brad DeSpain; Trico
  - Thomas Husted; VEA
  - Timothy Roberts; SRP
- Senior Executive Management
  - Donald W. Kimball, Executive Vice President & Chief Executive Officer
  - Gary G. Grim, Senior Vice President & Chief Operating Officer
  - Dirk C. Minson, Chief Financial Officer

II. Organization, Staffing, and Controls

A. Scope

This chapter of Liberty's report addresses the following subjects as they relate to fuel and power procurement and management:

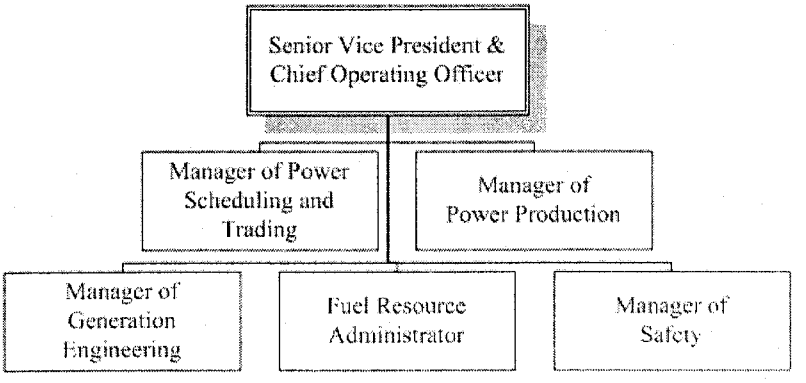
- Organization
- Staffing
- Procedures
- Goals and Objectives
- Controls.

B. Findings

1. Organization

a. Structure

Overall responsibility for fuel and power management within AEPCO rests with the Senior Vice President & Chief Operating Officer ("COO"). Specific day-to-day responsibilities for fuel management fall under the Fuel Resource Administrator. The Administrator reports directly to the COO, who, in turn, reports directly to the CEO (titled the Executive Vice President & Chief Executive Officer). The CEO reports directly to the AEPCO Board of Directors. The chart shows all of the operating groups that report to the COO.

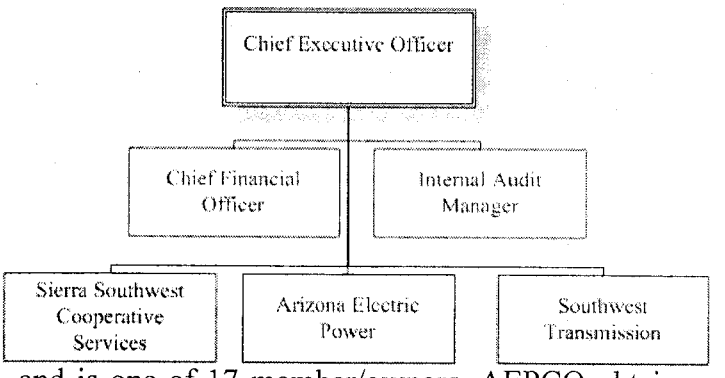


The Fuel Resource Administrator has responsibility for management and administration of all coal and transportation contracts. This individual plans and directs daily operational coal transportation activities, and assists with planning and development of coal and transportation strategic goals and objectives. The Fuel Resource Administrator also has responsibility for analysis of coal and transportation costs and procurement strategy and for the provision of recommendations on coal supply and transportation matters. The Administrator assists in the negotiation of coal supply and other coal and transportation agreements and related service terms and conditions. The current Fuel Resource Administrator has been in this position since early 2000. The Administrator did not then have a background in the coal business, but has undertaken concerted efforts to learn it since, including personal visits with coal suppliers, and tours of supplier coal mines in Wyoming, Colorado and New Mexico. The Administrator is active as a Director of the National Coal Transportation Association ("NCTA"), and serves on various of its committees. The NCTA exists to provide education and to facilitate resolution of coal transportation issues. It sponsors activities designed to exchange knowledge and viewpoints. It

operates through a variety of committees that address problems that arise in getting coal from producers to consumers, sponsor conferences, testify before regulatory authorities, and award scholarships.3

The Power Scheduling and Trading group buys and sells electric power, and buys natural gas. This part of the AEPCO organization compares the price of power available on the grid to AEPCO's own incremental cost of generation, and decides whether to run one of AEPCO's plants or to buy power.

AEPCO obtains a number of staff services (accounting, finance, legal, administrative services, etc.) from Sierra. SWTC provides substation, transmission, and power delivery functions necessary to transmit power to end-use members served by AEPCO's Class A distribution-cooperative members. The relationship between AEPCO and the other two entities is illustrated by the chart below. They share management and many employees, having been created from the same, formerly integrated organization. They were split into generation and transmission entities, with a third existing to provide them common services, in anticipation of industry restructuring.



AEPCO has an equity position in ACES, and is one of 17 member/owners. AEPCO obtains a number of specific and valuable services from ACES Power Marketing. An ACES Power Marketing representative is resident in AEPCO's offices and devotes 100 percent of her time to AEPCO matters. AEPCO obtains risk-management and certain scheduling and related services from ACES Power Marketing. Many of these services are provided from ACES Power Marketing's National Service Center in Carmel, Indiana. Effective with a new agreement signed at the end of 2007, ACES Power Marketing provides the following services to AEPCO:[4]

- Trading and counterparty controls and risk policies:
  - Credit:
    - Credit analysis and counterparty monitoring
    - Credit exposure monitoring and management
    - Credit negotiations
  - Contracts:
    - Master agreement (North American Energy Standards Board, International Swaps and Derivatives Association, etc.) negotiations
    - Contract administration – master agreements
    - Contract monitoring – master agreements
    - Structured/customized contract evaluations
    - Emission allowance contract negotiations
  - Trading control:
    - Deal capture and validation
    - Limits and authority policy compliance monitoring
    - Mark-to-market valuation

        - Reporting: transaction activity, mark-to-market data, forward pricing, historical pricing and portfolio cost tracking
    - Risk management and training:
        - Risk management policy development
        - Education and training
- Portfolio management and operations:
    - Portfolio management:
        - Origination (four months to five years)
        - Coal strategy development
    - Transmission and market development:
        - Regulatory participation (rule-making with existing and emerging Regional Transmission Organizations/Independent System Operators)
        - Reporting: trading and operational activities, market trends, Regional Transmission Organization/Independent System Operator developments
- Settlements:
    - Bilateral power and transmission settlements
    - Bilateral natural gas, transportation settlements
    - Reporting: as specified by AEPCO
- Portfolio modeling and risk analytics:
    - Portfolio modeling and transaction analysis:
        - Financial Transmission Rights/Congestion Revenue Rights evaluations
        - Pricing evaluation – standard/structured products
- Ad hoc consulting.

ACES Power Marketing also acts as AEPCO's agent for scheduling, accounting, and settlement relating to Anza Electric Cooperative, Inc., whose loads are within the California Independent System Operator's control area. In 2010, ACES Power Marketing has also started a financial-hedging program for AEPCO, to assist with managing AEPCO's exposure to power-purchase agreements that are tied to natural-gas prices. ACES Power Marketing works with AEPCO to structure the program, and then places the trades for AEPCO.[5]

b. Job Descriptions

Liberty reviewed job descriptions for positions related to fuel and power management. This review found them to be complete and in a format typically encountered in the utility industry.

2. Procedures

a. Procedures

AEPCO team members operate under a set of policies and procedures and models that guide the organization's activities. A complete set of fuel procurement procedures covers coal, natural gas, and power. The *Fuel Management* chapter of this report discusses these procedures. The procedures involving coal have been supplemented by specific Board Resolutions that address coal procurement, and establish specific authority transaction limits in an authority matrix. Extensive procedures also exist for natural gas and power trading and procurement practices. These procedures include a detailed trading authority matrix for short-term natural gas trading and for natural gas hedging activities.

The policies and procedures applicable to natural gas trading and to power trading include the following:

- Who has authority to execute transactions
- The commodities and products that can be transacted
- The authorized lead time and term for each transaction
- The authorized maximum price and volume
- Counterparty contract and credit requirements
- The process for approving new commodities, products or locations
- Other relevant factors associated with due diligence in authorizing transactions to be executed.

AEPCO Trading Sanctions define the procedures by which non-compliance with electric power and transmission, and natural gas trading practices will be addressed, and the consequences of non-compliance. The Trading Sanctions include general guidelines for determining appropriate disciplinary action, to ensure disciplined and consistent enforcement of the policies and procedures. The ACES Power Marketing on-site representative has responsibility for monitoring compliance with the trading practices limits and for reporting all non-compliance incidents to appropriate AEPCO staff and senior officers. The Natural Gas Trading Authority Practices and the Electric Power and Transmission Trading Practices each undergo updating as necessary. The most-recent versions of both bear a date of March 29, 2010.

AEPCO's power and gas traders fill out deal tickets as they agree to transactions. The real-time power traders fill out MS Excel™ spreadsheets. The transaction data from the deal tickets and the spreadsheets are entered into Allegro transaction-tracking software, which ACES Power Marketing operates and maintains. The ACES Power Marketing on-site representative then uses the transaction-tracking system to manage application of authority limits to AEPCO personnel, and to manage credit limits for authorized counterparties.

Transactions in Allegro are matched daily with the traders' deal tickets. Any differences between the deal-ticket data and the data in Allegro is resolved the next day.

ACES Power Marketing analyzes the credit of counterparties of all its members and clients in its National Service Center in Indiana. Limits for each counterparty are entered directly into the Allegro data base for each member or client.

b. Standards of Ethical Conduct

Several sets of procedures related to ethical conduct guide AEPCO employees. The first set of procedures seeks to ensure adherence to trading practices, and it sets forth the consequences of non-compliance by any individual employees. The sanctions provide general guidelines for determining appropriate disciplinary action, ensuring disciplined and consistent enforcement procedures as they pertain to trading. The ACES Power Marketing Trading Control Specialist monitors compliance with the Trading Practices Limits, and reporting all non-compliance incidents to the appropriate AEPCO staff, and the Risk Management Committee, as set forth in the procedures. Employees involved in these types of activities must sign a statement stating that they have read, understand, and will comply with these procedures.

All AEPCO employees must also comply with Corporate Policy No. 3-5, *Code of Employee Conduct.* This code establishes comprehensive procedures for ethical conduct, established by the Board of Directors. The CEO has management responsibility for this policy, and for assuring compliance with a procedure requiring all employees to acknowledge in writing that they have received, understand, and will comply with the policy.

c. *Goals and Objectives*

AEPCO does not have specific documents titled as Business Plans, or Goals and Objectives, relating to coal, natural gas, or purchased power. It does have detailed hedging plans developed yearly with the objective of stabilizing natural gas prices. The *Gas Hedging* chapter discusses this subject. AEPCO did not have any long-term power purchase plan for the 2008 or 2009 time period, due to previously procured purchased power agreements and existing resources. The only power purchases committed to in this time period related to unit outages and short-term economy purchases.

AEPCO's coal-related goals and objectives, starting in 2007, related to replacing its primary long-term coal contract. Prior to January 1, 2009, AEPCO's coal supply originated primarily from the Colowyo Mine in Colorado and from the Jacob's Ranch Mine in the Powder River Basin area of Wyoming, under a five-year contract with Kennecott Colorado Coal Company, a subsidiary of Rio Tinto America. This contract was to expire on December 31, 2008. The coal from Wyoming was transported under a rate established by the Union Pacific Railroad (UP), and modified from time to time. Part of AEPCO's planning challenge arose from notification by the rail carrier in 2008 that transportation rates would increase dramatically beginning in 2009. Thus, the contract replacement planning process that had begun in 2007 gained even more urgency in 2008 with this information from UP. AEPCO has provided a log of its multiple meetings with railroads and coal companies related to its planning for coal contract replacement that started in early 2007. The *Fuel Contracting* chapter discusses contracting in more detail. Overall, the planning and negotiation process in 2007 and 2008 covered a period of 21 months before the final contract was executed in late 2008 for a new coal supply from New Mexico for the Apache Station.

C. Conclusions

1. The AEPCO organization is staffed with competent individuals in the fuel and power procurement and management areas.

The organization of the Senior Vice President & Chief Operating Officer, who has overall responsibility for procurement and management of fuel and power, is staffed with competent individuals who have demonstrated dedication to their work, and a sound understanding of the important dimensions of their individual jobs. Liberty found the organizational abilities of these individuals, and the detailed information that they have been able to provide, upon request, to be appropriate and sufficient.

2. Job descriptions for positions in the fuel and power procurement and management areas are satisfactory.

Job descriptions for the positions in the fuel and power procurement and management area are current, and typical of what is normally encountered in this area of activity in electric utility organizations.

3. The procedures for fuel and power management and procurement are satisfactory.

The procedures for activities in the fuel and power procurement and management area are current, and typical of what is normally encountered in this area of activity in electric utility organizations.

4. AEPCO has satisfactory procedures related to code of conduct and ethical behavior of employees.

AEPCO's procedures for code of conduct have recognized the particular risks to which the Company is exposed in the areas of fuel and power procurement and management, including hedging. The Cooperative has developed detailed procedures that thoroughly cover this area. The Cooperative also has a separate code of conduct procedure that all employees must sign, and confirm their understanding and compliance with the tenets of ethical behavior.

5. AEPCO has maintained a strong and effective relationship with ACES Power Marketing.

AEPCO had a relationship with ACES Power Marketing for many years, proceeding until recently as a customer only. However, four years ago, AEPCO became a member/owner of ACES Power Marketing with an equity position. There is now in residence a full-time ACES Power Marketing representative in AEPCO offices. AEPCO has made use of a valuable range of services for AEPCO that relate to trading and counterparty controls and risk management, and provision of valuable industry data and mark-to-market analyses.

6. AEPCO's approval-authorities matrix and trading controls are appropriate.

AEPCO documents related to policies and procedures for trading, and approval authorities are thorough. These documents exhibit the expertise to which AEPCO has access through its relationship with ACES Power Marketing. These materials are all first-rate, and demonstrate that AEPCO is benefiting from its relationship with ACES Power Marketing.

D. Recommendations

None.

III. Fuel Contracting

A. Background

This chapter addresses the following areas related to coal procurement, coal pricing and contracts:

- Coal Fuel Burned
- Coal Sources
- Coal Prices
- Contract Purchases and Summaries
- Contract Actions
- Transportation

In addition, this chapter addresses the natural gas contract status in the following areas:

- Commodity supply
- Commodity delivery
- Commodity storage

B. Findings

1. Coal Forecasted Versus Actual Burns

Rail transportation provides the primary transport method for coal consumed by AEPCO to generate electricity at its Apache Generating Station. AEPCO receives coal under a combination of long-term and short-term (or "spot") contracts. Long-term contracts consist of obligations whose term equals or exceeds one year; spot agreements have durations of less than a year. The Apache coal units (ST2 and ST3) each has a net rating of 175 MW. Together, their annual coal consumption has run in the 1.5 million ton range.

AEPCO burns low sulfur western coals from the Wyoming Powder River Basin ("PRB"), from Western Colorado, and from New Mexico. These coals range in sulfur content from a low of approximately 0.36 percent for Western Colorado coal to 0.93 percent for New Mexico coal.

The following table summarizes the annual comparisons between coal burn forecasts and actual coal burned at Apache.

Coal Consumption: Forecast Versus Actual

Item	2006	2007	2008	2009
Forecast Tons	[redacted]	[redacted]	[redacted]	[redacted]
Actual Tons	[redacted]	[redacted]	[redacted]	[redacted]
Difference – Tons	[redacted]	[redacted]	[redacted]	[redacted]
Difference - Percent	[redacted]	[redacted]	[redacted]	[redacted]

The next graph shows total coal consumption in tons, by month from September 2005 through December 2009. The graph compares this actual burn information with AEPCO's forecasts of burns for each month.

[redacted]

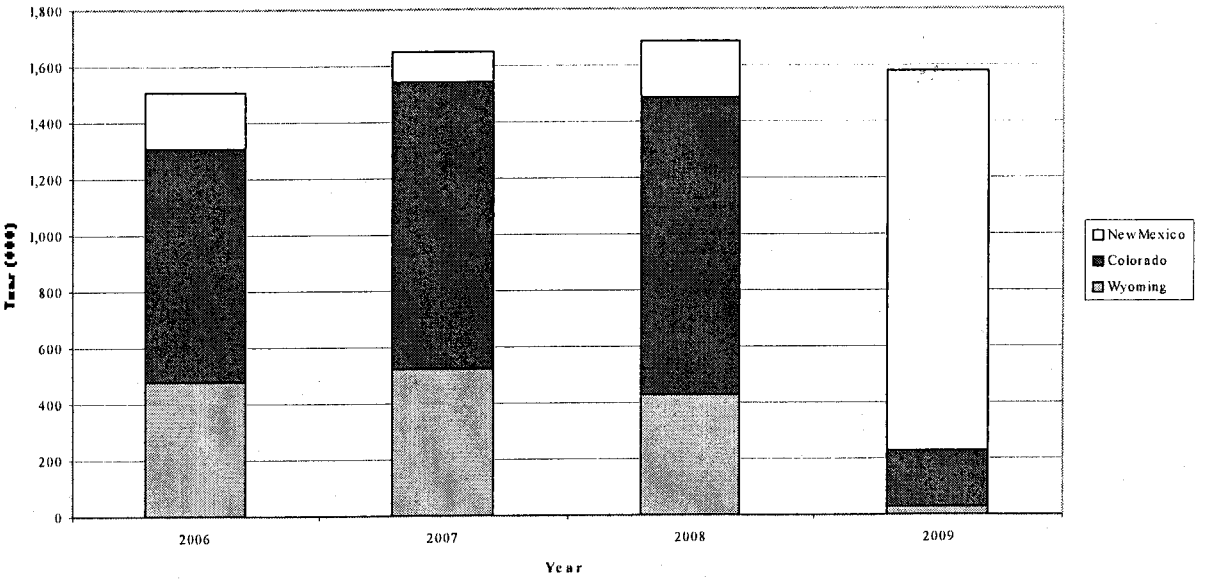
The preceding graph and table show a fairly normal variance between forecasts and burns. There are two exceptions: (a) AEPCO made the decision to postpone planned maintenance for two months in late 2007, and (b) actual coal consumption has been significantly less than planned since October 2008. Load has been reduced due to maintenance issues on the generating units and due to decline in market competitiveness for power from the coal-fired units, and consequently less off-system sales. The *Engineering Review/Plant Operations* chapter of this report addresses plant maintenance issues.

2. Coal Sources

The following graph shows the relative distribution of AEPCO's three supply sources: the Powder River Basin of Wyoming, Western Colorado, and New Mexico. The graph makes apparent the dramatic shift in coal supply sources that took place in 2009 because of overall coal supply economic considerations. Section 4 below discusses the economic issues underlying this shift.

For the years 2006 through 2008, Wyoming supplied approximately 500,000 tons per year, Colorado 1,000,0000 tons per year and New Mexico 200,000 tons per year. However, in 2009, the New Mexico proportion shifted to approximately 1,350,000 tons per year, with Colorado at 200,000 tons per year, and Wyoming supply negligible.

Geographic Distribution of Coal Supply



3. Coal Prices

The next graph shows delivered coal prices for coal consumed at the Apache Generating Station.

[redacted]

[redacted]

AEPCO prepared in 2005 a coal-price forecast for the years 2005 through 2009. AEPCO has updated the forecast annually (in either the 3rd or 4th quarter) as the Cooperative prepared its operating plan for the following year.

4. Contract Purchases and Summaries

During the period from September 1, 2005 through 2009, AEPCO made five purchases of coal under contracts with terms of one year or greater, as the following table displays:

AEPCO Term Coal Procurement: September 2005 – December 2009

Supplier	Term	mTons/ Yr	Year	Price $/T*	BTU/lb	%S
Term Coal Contracts						
COALSALES, LLC El Segundo & Lee Ranch Mines New Mexico	1/1/09-12/31/11	1,100 1,150 1,150	2009 2010 2011	[redacted]	9,200	0.93
Chevron Mining, Inc. McKinley Mine New Mexico	1/1/09-12/31/09	250	2009	[redacted]	9,800	0.45
Kennecott Colorado Coal Rio Tinto Energy America Colowyo Mine - Colorado	1/1/09-12/31/09	200	2009	[redacted]	10,400	0.36
Rio Tinto America Jacob's Ranch Mine Wyoming	1/1/08-12/31/08	300	2008	[redacted]	8,800	0.80
COALSALES, LLC Twentymile Mine - Colorado	1-1-08-12/31/08	100	2008	[redacted]	11,300	0.49

AEPCO applies a structured process to purchasing its coal supplies. The procurement process starts with development of an RFP that specifies the details of the required coal supply. The specified parameters include desired length of term, preferred source of supply, delivery point, pricing provisions, quality and quantity. For example a 2008 procurement resulted in a contract with COALSALES, LLC for delivery of approximately 1,000,000 tons of coal per year for the years 2009 through 2011. AEPCO sent the RFP to a list of five potential coal suppliers. These potential suppliers (covering coal from Wyoming, Colorado and New Mexico) comprised those suppliers that AEPCO believed were capable of providing the desired coal supply.

Multiple bids came from all potential suppliers. AEPCO began a detailed analysis process that considered all alternatives of supply and various blends of coals to achieve optimum economics and performance at Apache. The analysis included a three-year projection of estimated costs from various combinations of suppliers. As a result, for each year of potential supply, four different supply scenarios came under consideration. The different supply scenarios also included different rail-sourcing possibilities. The Vista Model has formed an important part of the AEPCO evaluation process. The Vista Model analyzes the effects of various coal qualities on coal-fired generating units. AEPCO conducted all evaluations on the basis of final delivered cost to Apache in dollars per MMBtu.

After AEPCO identified the most optimum economic package of coal supply, it began a negotiation process with the lowest cost supplier, which in this case was COALSALES. Several offers and counter offers ensued, before finally converging on a deal that both parties could abide. At this point, management provided the details of the potential coal supply agreement to the AEPCO Board of Directors meeting in executive session, for approval. The potential procurement underwent detailed discussion, and the Board approved management discussions with the vendor about contractual details. On November 24, 2008, AEPCO signed the agreement with COALSALES.

AEPCO generally followed a similar process for most coal procurement, with occasional exceptions. For example, in late 2007, AEPCO was preparing to issue an RFP for procurement of 300,000 tons of coal for 2008 delivery. AEPCO was aware of potential supplies available, and of prices that were being offered by suppliers at this time. [redacted]

Liberty examined all of AEPCO's coal procurement between September 2005 and December 2009, including both term and spot purchases. In all cases, AEPCO performed detailed analyses, followed appropriate procedures, obtained proper approvals, and fully justified the procurement.

5. Contract Actions

During the period from September 1, 2005 through 2009, AEPCO actively sought on three different occasions to modify its coal supply arrangements through coal resales and swaps. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

These transactions produced both the financial benefit just described and the avoidance of high rail charges. The procurement of high-Btu and low-sulfur New Mexico coal addressed the need for AEPCO to secure shipment of Colowyo coal at Union Pacific's high rates in 2009. Instead, AEPCO was able to ship New Mexico coal under a more attractive BNSF common carrier agreement.

During the period from September 1, 2005 through 2009, there were no coal contract price redeterminations, no force majeure provisions invoked by AEPCO or its vendors. There were no coal-contract terminations for reasons other than normal contract date expirations. Currently, no open or unresolved coal contract issues exist.

6. Transportation

Apache receives coal from sources on the Union Pacific Railroad and on the BNSF Railway. For the years 2004 through 2008, AEPCO's only contracted fuel transportation was with the Union Pacific Railroad. It provided for a minimum volume of 1,000,000 net tons of coal per year.

Volumes of coal shipped via the BNSF Railway moved under common-carrier pricing authorities (tariffs). After 2008, AEPCO shipped coal solely under railroad tariffs, and has not had any open or uncontracted coal transportation.

The following tables show the coal shipped under contract and under tariff from 2005 through 2009.

Coal Shipped under Union Pacific Contract

Year	Origin	Actual Volume	Minimum UP Annual Volume
2005	Colorado &Wyoming	1,235,899	1,000,000
2006	Colorado &Wyoming	1,300,874	1,000,000
2007	Colorado & Wyoming	1,577,383	1,000,000
2008	Colorado & Wyoming	1,444,751	1,000,000
2009	N.A.	N.A.	N.A.

Coal Shipped Under BNSF Tariff

Year	Origin	Actual Volume	Minimum BNSF Annual Volume
2005	New Mexico	279,312	200,000
2006	New Mexico	203,032	N. A.
2007	New Mexico	107,419	N. A.
2008	New Mexico	197,845	N. A.
2009	New Mexico	1,353,916	N. A.
2009	Montana	27,850	N. A.

Rates for rail transportation of coal have formed a matter of significant attention for AEPCO in 2008 and 2009. In 2008, the Union Pacific issued a 2009 transportation rate proposal that would resulted in potential, dramatic price increases for AEPCO. At the same time, AEPCO was considering a new coal-supply agreement to run for three years from 2009 through 2011. Primarily due to expected large increases in transportation costs, AEPCO's 2008 coal RFP process threatened to produce an increase in total coal and transportation costs for 2009 [redacted]

This dramatic potential increase in transportation costs influenced AEPCO fuel strategies in a number of ways, which the report chapter titled *Fuel Management* addresses. Briefly, the potential increase in 2009 transportation costs led to [redacted]

The proposed, dramatic increase in transportation rates led AEPCO to file a rate-complaint case with the U.S. Surface Transportation Board ("STB"). The case remains ongoing; at the same time, AEPCO is negotiating with the Union Pacific to reach a rail settlement agreement. AEPCO would like to produce a result that makes PRB/Colorado coal competitive with New Mexico

coal. There have been offers and counter offers, and rail-rate negotiations with the Union Pacific continue. Failing an agreeable settlement with the Union Pacific, AEPCO would continue the pursuit of the STB case in an attempt to reach an ordered resolution of its complaint.

7. Natural Gas Commodity Supply

AEPCO buys all of its natural gas under a standard form contract developed by the North American Energy Standards Board ("NAESB"). The NAESB contract was originally developed in the 1990s as the Gas Industry Standards Board ("GISB")() contract. In 2002, it was modified and re-named, as the GISB expanded its role to include standards and business practices in the wholesale and retail segments of the electric-power industry. The NAESB contract was updated again in 2006. It is widely used by suppliers and users of natural gas throughout the U.S. and Canada. The NAESB contract specifies general terms and conditions, under which counterparties agree to individual transactions (with transaction-specific details such as price, delivery location, and firmness, for example), and then "confirm" each specific transaction's unique terms with a one-page statement. The Buyer usually sends to the Seller such confirmations, which the counterparties often refer to as "Schedule A." These confirmations allow the parties to assure mutual agreement on the details of the agreed transaction, which the confirmation documents.

AEPCO has NAESB contracts in place with [redacted] counter-parties.[6] It buys its gas under those contracts in two ways:

- Up to [redacted] percent of its gas is bought on a "forward" basis; *i.e.*, contracted for some months in advance of its intended use, as part of AEPCO's hedging program. AEPCO buys this gas pursuant to an informal quotation process.
- AEPCO buys the other [redacted] percent daily, using an electronic trading platform.

AEPCO fills its forward supply requirements from [redacted] suppliers: [redacted]. The Cooperative limits its requests to quotations from these [redacted] counterparties because [redacted]

[redacted] suppliers also provide other conveniences as part of maintaining a relationship with AEPCO. One example arises in cases where [redacted]

AEPCO's daily purchases come through the Intercontinental Exchange ("ICE"), which is a standard industry practice for such acquisitions. Buyers and sellers post offers electronically on ICE; the platform then matches them with each other. Both buyer and seller can restrict valid

offers to counterparties with whom they have in-place standard contracts. AEPCO, as do a number of other Generation and Transmission cooperatives (among others), uses the services of ACES Power Marketing to manage transaction activities. An ACES Power Marketing representative on-site at AEPCO maintains information about approved AEPCO counterparties and authorized credit limits, to assure that transactions are with approved counterparties and remain within pre-established credit limits.[7]

8. Gas Transportation Contracts

AEPCO's Apache Generating Station is served exclusively by the El Paso Natural Gas Pipeline system ("El Paso"). The U.S. Federal Energy Regulatory Commission ("FERC") regulates El Paso's rates and terms of service. Until 2006, AEPCO was an "all-requirements" customer of El Paso: AEPCO has always bought its own gas, but El Paso managed the pressures and flows to ensure that the Apache Station received the amount of gas needed at all times.

At that time, as part of a rate case, El Paso was required to restructure its service offerings and rates. AEPCO has since used conventional gas-transportation contracts with El Paso, supplemented with contracts for "premium" services. These supplemental agreements allow it to take the maximum delivery quantity over 8 or 12 hours, rather than the usual 24 hours.

[redacted]

[redacted]

AEPCO participated actively in negotiation of these contracts. AEPCO examined the patterns in its gas usage, and then sought contract quantities to match that usage. El Paso offered certain quantities, but AEPCO adjusted and added to El Paso's initial offerings in order to improve the "fit" between its contracts and its operational requirements. Among other things, [redacted]

[redacted] All of the contracts expire in September 2016.

9. Gas Storage Contract[8]

AEPCO has a gas storage agreement with [redacted] The pipeline may have a separate rate schedule for services of this type, or it may bill for them at its normal rates for transportation service.

AEPCO's agreement with [redacted] provides for [redacted] The contract was originally entered in [redacted]

AEPCO reports [redacted]

Park-and-loan services are essentially short-term storage services offered by pipelines. "Parking" is analogous to storage injection, but essentially amounts to withdrawing less gas from the pipeline than scheduled. "Loaning" is analogous to storage withdrawal. It occurs when a customer withdraws more than its scheduled quantity from the pipeline. Park-and-loan services are inherently interruptible because the pipeline is not always able to accommodate additional volumes in the pipeline in response to a customer's request to withdraw less than scheduled, or to allow a customer to withdraw more than its scheduled quantity. Park-and-loan services are also inherently short-term, as pipelines must keep receipts and deliveries essentially in balance over time in order to operate properly.

10. Gas Contract Documentation

For most major decisions, the investigation and analysis performed by AEPCO personnel and consultants are summarized in an Executive Staff Summary submitted to the Board of Directors. Minutes of Board Meetings contain Board Resolutions setting forth the decision made by the Board. Materials provided to Liberty included the Staff analysis and Board Resolution regarding the [redacted] contract as an example of the Cooperative's documentation processes.

Gas purchase decisions are supported by Board approval of AEPCO's hedging policy. Individual purchases are documented through a transaction-tracking system administered for AEPCO by ACES Power Marketing. Those latter purchases are monitored continually by ACES Power Marketing.[9]

C. Conclusions

1. AEPCO's forecasts for coal consumption have remained relatively stable compared to actual consumption, with two major exceptions.

AEPCO had done a reasonable job of forecasting coal consumption, but there have been two outlying sets of circumstances. The first involved two months in late 2007, when AEPCO made the decision to postpone planned maintenance. The second exception has been ongoing since October 2008. Actual coal consumption has been significantly less than planned. Load has been reduced due to maintenance issues on the two Apache coal-fired generating units, and due to decline in market competitiveness for power from the coal-fired units, consequently less off-system sales.

2. AEPCO has taken effective coal contract action, through coal resales and swaps, to optimize coal supply.

AEPCO has conducted coal resales and swaps in order to improve its coal supply situation. [redacted]

3. Documentation maintained by AEPCO in support of its coal procurement is thorough, and meets the standards expected from electric utility fuel procurement organizations.

Liberty found that the documentation necessary to support coal procurement decisions was available and satisfactory in content.

4. AEPCO acted appropriately in 2008 to enter a three-year coal supply agreement with COALSALES for coal sourced from New Mexico.

AEPCO's initial considerations associated with evaluation of a potential new three-year coal supply was affected by the possibility that costs could increase by as much as 124 percent because of dramatic increases in transportation costs on the Union Pacific. AEPCO continued its pursuit of alternatives, and engaged in negotiations with alternate suppliers in an effort to maintain reliable coal supply, at the best available prices. The Cooperative identified that New Mexico coal might offer be reasonable alternative to Wyoming and Colorado coals. After exchanging numerous offers and counter offers, a deal was reached with COALSALES for coal from the New Mexico El Segundo and Lee Ranch Mines.

5. AEPCO has acted appropriately in dealing with the dramatic increase in coal rail transportation rates.

Faced with the potential of unrealistic increases in rail transportation rates from the Union Pacific, AEPCO has acted appropriately. It has shifted its major coal supply contract from Union Pacific sourced coal to BNSF sourced coal. It has filed suit with the STB in protest of the high Union Pacific rates. Concurrently, AEPCO has attempted to negotiate with the Union Pacific in an effort to keep all of its options open.

6. AEPCO has appropriately developed, and is properly maintaining, its gas-supply relationships.

The natural gas industry, and more recently the electric-power industry, has invested considerable effort in standardizing its energy-supply contracts and business practices at the wholesale and retail levels. AEPCO benefits from this effort in having standard form supply agreements available for use. AEPCO accesses this benefit through its use of the NAESB standard form contract for its gas supplies.

Maintenance of this benefit requires current information regarding the creditworthiness of gas-trading counterparties. This is one of the functions that AEPCO obtains through its relationship with ACES Power Marketing. This relationship strikes Liberty as an efficient way to discharge this vital function.

7. AEPCO's method for buying its forward gas supplies offers advantages, but the Cooperative should try to expand the number of suppliers for those purchases. *(Recommendation #1)*

AEPCO buys its forward gas supplies from [redacted] suppliers, [redacted] The more uncertain issue is whether other suppliers would offer similar inducements. At recent, depressed market prices, AEPCO's forward purchases amount to [redacted] It is reasonable to consider the possibility that more suppliers would be interested in a share of that business. It is appropriate that AEPCO formally solicit interest from others in participating in its RFPs while providing similar advantages to those offered by the [redacted], existing forward suppliers.

8. AEPCO was effective in negotiating its gas-transportation contracts.

Like many other gas pipeline systems, El Paso was required to restructure its service offerings in response to concern raised by its non-electric-generation customers that electricity generators were not paying their "fair share" of pipeline costs. Creation of premium products that allow hourly variation in gas flows, for example, has been a common pipeline industry response to those concerns.

AEPCO's response to these developments was appropriate and effective. AEPCO analyzed the patterns in its usage in terms of the services that El Paso was offering, and knew what it was seeking when it went into its negotiations with El Paso. The results were satisfactory from the perspective of AEPCO's customers.

9. AEPCO's gas storage service is appropriate.

As discussed in the chapter on Fuels Management, AEPCO makes good use of this storage capability, as part of its hedging program and to provide operational flexibility. [redacted]

The storage-service contract between AEPCO and its service provider, [redacted]

10. Gas contract documentation is satisfactory.

For major contracts, the decision materials presented to the Board contain adequate information to support regulatory review. For commodity-purchase decisions, the transaction-tracking system maintained by ACES Power Marketing provides a sufficient record to support an after-the-fact review.

D. Recommendations

1. Solicit interest in additional suppliers for AEPCO's forward gas purchases. *(Conclusion #7)*

Liberty believes that AEPCO's forward purchases of natural gas supplies may be large enough to generate interest from more than [redacted] suppliers. AEPCO's gas-transportation contracts give it access to purchasing points in both San Juan and West Texas supply basins. [redacted] are not the only sellers with gas supplies available in those places.

[redacted] are material. Nevertheless, there is reason to believe that AEPCO is a sufficiently attractive buyer to attract others willing to offer such terms. In any event, solicitation of additional participation will resolve any uncertainty in that regard. It is generally sound to expand participation in purchase solicitations.

IV. Fuel Management

A. Background

This chapter addresses the following areas related to fuel supply management:

- Coal Receipt Information
- Coal Weighing, Sampling and Analysis
- Coal Contract Administration
- Coal Inventory Control
- Natural Gas Supply Management.

B. Findings

1. Coal Receipt Information

Apache Station coal arrives in unit trains, which AEPCO unloads at its coal-unloading facility. AEPCO manages receipt information with a variety of internally developed spreadsheet programs developed specifically for the purpose of monitoring receipt of coal. These programs track coal delivery quantities and qualities, and enable AEPCO to monitor contract compliance. The programs indicate the trainload quantities of coal as received, and the corresponding coal quality. AEPCO cross-checks data in the spreadsheets against contractual requirements for coal quantity and quality.

AEPCO maintains an estimated train delivery schedule in the Station Control Room, and regularly logs into the Union Pacific Web site in order to confirm specific train status and expected arrival time. When the unit train of coal arrives at the unloading facility, the facility operator uses a "Train Unloading Data Log" (Log) that is specific for each train. The Log contains a complete record for the train unloaded, including car numbers, coal weights from the belt scales, and appropriate arrival and departure times. The log also contains information on any coal cars that failed to open and unload coal. At completion of train unloading, the facility operator sends this Log to the Station Control Room.

In the Station Control Room, data from the Log is transferred to a Union Pacific summary sheet (the "Union Pacific Railroad NCSC"). AEPCO personnel fax the Union Pacific Railroad NCSC form and the Log to the Union Pacific Railroad and to the AEPCO Fuel Resource Administrator ("Administrator"). The Administrator uses this coal receipt information as primary information for coal received dates, quantities, and train numbers. The Administrator cross-checks information on the Log with tonnage information provided by the coal mines. The only problem Liberty observed with the Log is that it does not indicate the source of the coal.

2. Coal Weighing, Sampling, and Analysis

AEPCO's coal contract arrangements provide that weighing, sampling, and analysis of coal delivered to AEPCO will come from information collected at the coal mines, as coal is loaded into unit trains. Coal weighing and sampling takes place during the loading of coal into unit trains. ASTM standards govern the sampling. A split of the sample collected goes to AEPCO for its own use in cross-checking analytical information. Several times a year, AEPCO sends these

sample splits to an independent laboratory to provide verification of the sample analysis information provided by the coal mines.

AEPCO's coal contracts require the vendor to analyze coal sampled, in accordance with ASTM standards, and send a report of its coal sample analysis within 48 hours after the loading of each trainload of coal to AEPCO by email. The vendor also determines the weights of coal loaded into each railcar in each shipment of coal to AEPCO, using either certified scales or a certified batch weight system maintained by the coal mine. The sum of the railcar net weights for each train of coal comprises the accepted contractual weight of the coal delivered in each shipment. The vendor provides, on departure from the mine, a trainload manifest identifying the total weight of each railcar of coal for each trainload shipped to AEPCO. Liberty examined the scale calibration records provided by each coal mine, and found them to be satisfactory.

3. Coal Contract Administration

The Fuel Resource Administrator ("Administrator") has responsibility for contract administration. The Administrator, who reports directly to the Senior Vice President and Chief Operating Officer, follows a comprehensive set of policies and procedures designed to provide guidance in the procurement of coal supply and coal transportation as necessary to support energy generation at Apache. These procedures also contain a separate section specifically focused on maintenance of target coal inventory levels. Inventory procedures include specific plans to be implemented should any unforeseen event prohibit AEPCO from obtaining normal coal supply.

The coal procurement procedures contain the following specific sections:

- Coal Supply and Transportation Analysis and Forecasting
- Development of Coal and Transportation Objectives and Strategy
- Coal Transportation Request for Proposal Process
- Coal Transportation Approvals and Finalization of Agreements
- Coal Supply Request for Proposal Process and Analysis
- Coal Supply Approvals and Finalization of Agreements
- Coal Supply and Transportation Delivery Planning and Management.

The Administrator daily administers coal contracts, and provides regular input of fuel information into the fuel accounting system. The Administrator communicates daily with fuel personnel at the Apache Station, and meets monthly at the station to discuss fuel management issues with a group that includes representatives from all disciplines including Maintenance, I&C, Process Control, Environmental, Engineering, and Station Fuel Management.

4. Coal Contract Compliance

a. Quantity Administration

During the period from September 1, 2005 through 2009, AEPCO did not experience any situations where quantities of contracted coal were not delivered.

b. Quality Administration

During the period from September 1, 2005 through 2009, AEPCO did experience some situations where some coal delivered did not meet quality requirements. The next table summarizes these occasions.

Coal Quality Variations

Year	Month	Company/Mine	Btu/lb	Description
2009	May	COALSALES El Segundo	8,734	Below 8,900 Btu/lb reject limit. Train rejected; buyer could not be found. AEPCO accepted train, negotiated $4.00/ton discount.
2008	Multiple: 31 times	Rio Tinto Colowyo Mine	Below 10,100 Btu/lb limit	AEPCO accepted all trains; received $0.50/ton discount per contract.
2008	September	Entergy Services Colowyo Mine	9,851	Below 10,000 Btu/lb reject limit. AEPCO accepted train and received $10.00/ton discount.
2007	Multiple: 10 times	Rio Tinto Colowyo Mine	Below 10,100 Btu/lb limit	AEPCO accepted all trains; received $0.50/ton discount per contract.
2006	Multiple 4 times	Rio Tinto Colowyo Mine	Below 10,100 Btu/lb limit	AEPCO accepted all trains; received $0.50/ton discount per contract.
2005	November	Rio Tinto Colowyo Mine	Below 10,100 Btu/lb limit	AEPCO accepted all trains; received $0.50/ton discount per contract.

5. Coal Inventory

a. Targets

AEPCO has established an inventory policy. The Coal Supply Group reviews it annually, taking into consideration the industry average of coal inventory, coal market conditions, coal blending objectives, transportation pricing, financial considerations (such as carrying costs), and other strategic objectives. The current inventory target is 40 days of burnable coal available in the stockpile at a two-unit nominal capacity factor of 95 percent. The policy states that inventory will be no more than 25 percent above or below this level. The 40-day target equates to an inventory of approximately 176,000 tons of coal, exclusive of the amount (approximately 15 days, or approximately 66,000 tons) deemed not recoverable.

b. Recent Coal Inventory Growth

AEPCO decided to permit inventory to grow in 2008, in order [redacted]

[redacted]

Coal Inventory Levels (Days)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005									9	12	25	18
2006	18	13	19	25	21	15	15	15	18	25	27	23
2007	16	16	18	15	26	23	21	30	27	27	40	40
2008	39	45	66	70	70	66	69	60	57	49	68	76
2009	75	77	94	111	119	116	116	120	128	125	134	137

Coal Inventory Levels (Tons)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005									39,269	52,635	105,112	74,232
2006	77,035	57,965	80,884	108,869	90,789	64,504	64,612	65,462	77,544	109,754	115,273	99,679
2007	68,870	71,083	79,185	66,360	113,890	99,333	92,470	127,201	114,590	117,763	171,697	169,930
2008	167,663	190,882	278,336	297,801	296,195	279,600	283,455	253,441	241,583	208,135	290,584	323,248
2009	319,596	327,955	397,124	470,806	500,838	492,181	489,430	506,796	540,759	526,848	567,071	576,743

AEPCO's growth in coal inventory exceeded its expectations. For the last several months of 2008, AEPCO's generation load was less than anticipated, which led to lower than estimated coal burn at Apache. Decreased Apache generation continued into and through 2009. Reduced energy demand from AEPCO's members contributed to this result. In addition, during 2009, AEPCO experienced unplanned coal unit outages and experienced unit derates at Apache. [redacted]

The report chapter titled *Engineering Analysis/Plant Operations* discusses Apache performance.

6. Physical Coal Inventory Measurements

Since 2005, AEPCO has been conducting annual coal inventory surveys to confirm coal inventory levels, and to ensure correspondence between book and physical inventory amounts. Starting in mid-2008, AEPCO began biannual physical surveys, because of the significant amount of coal in inventory, as compared to previous levels. Physical inventory measurements have been conducted using aerial flyover techniques and density measurements obtained through bore-hole samples. AEPCO has made adjustments to book inventory if the difference between book and physical inventory exceeds 1.5 percent. In making the adjustment, AEPCO subtracts the 1.5 percent measurement uncertainty from the difference in tons between physical and book inventory before any adjustment is made. For example, in the 2005 measurement, the difference between physical and book inventory was 3,592 tons. The 1.5 percent degree of uncertainty

represents 2,067 tons, which AEPCO subtracted from the tonnage difference of 3,592, to obtain the adjustment quantity of 1,525 tons to add to book inventory.

The following table shows the results of coal pile physical inventory measurements since 2005.

Coal Inventory Comparison – Physical vs. Book Inventory

Date	Book Inventory	Physical Inventory	Difference (tons)	Difference (%)	Adjustment (tons)
12/05	134,232	137,824	3592	2.6	1525
12/06	159,679	149,113	(10,566)	(7.1)	(8305)
12/07	229,021	213,294	(15,727)	(7.4)	(12,492)
7/08	352,952	338,379	(14,574)	(4.3)	(9,498)
12/08	383,248	387,398	4150	1.1	-0-
6/09	552,181	516,963	(35,218)	(6.8)	(27,464)
12/09	636,743	606,144	(30,599)	(5.0)	(30,599)

7. Natural Gas

AEPCO has steam units that run on coal and combustion turbines that run on natural gas. AEPCO also has a combined-cycle unit that runs on gas. In the late 1980s or early 1990s, the steam units were retrofitted to be able to run on gas, but at current prices they are running on coal. The steam units generally have run in the base-load position; *i.e.*, they run steadily (unless they are down for maintenance) year-round. The gas turbines have generally run more in the summer and less in the winter. AEPCO generally does not run the combined-cycle unit outside the months from June through September.

AEPCO's Resource Planning group takes load forecasts from the member cooperatives, and assembles them into a forecast of requirements for power. The group then runs these forecasts through a dispatch-simulation computer model (PROMOD) to forecast:

- Generation by each of AEPCO's generating units
- Purchase requirements under each of AEPCO's long-term power-purchase contracts.

The forecasts initially cover the next five years, and then undergo multiple updates during the year as part of AEPCO's budgeting and business-planning processes.

The generation forecasts also produce estimates of requirements for generating fuels. Fuel prices and forward power prices within AEPCO's power-coordination area serve as inputs to the forecasting process. Outputs therefore include possible economy power purchases and sales, as well as quantities of fuel required, if power purchases or sales are indicated by relative price levels. Through this process, AEPCO generates fuel requirement forecasts by month for the next five years.

AEPCO's current hedging strategy calls for the Cooperative to begin to buy the gas forecast to be needed [redacted] ahead of the month when it will be needed. The strategy is [redacted] The report chapter on Fuel Supply Contracting describes

how AEPCO secures much of this gas from [redacted] vendors [redacted]

That chapter also discusses AEPCO's contract for gas storage. The storage available under that contract is sufficient to meet [redacted]

Once [redacted] AEPCO buys the balance of its gas [redacted] The Cooperative balances these purchases against [redacted] If AEPCO can buy the power cheaper than it can buy the gas and generate the power, it will do so. Conversely, if it can buy the gas and generate the power for less than it can buy the power, it will do that, instead.

AEPCO generally [redacted]

AEPCO uses its gas storage [redacted]

8. Fuel Oil

AEPCO's Gas Turbines No. 1 and 2 can use diesel fuel as an alternative to natural gas. Gas Turbine No. 3 can burn a range of fuel oils, from No. 2 (diesel fuel) to No. 6 (heavy fuel oil). Steam Unit No. 1 could burn fuel oils, and fuel oils were used in the igniters for the coal units. However, natural gas has been available; therefore, there has been no need to use fuel oils for back-up fuels. Also, the igniters were switched to natural gas in the 1980s. Thus, while Gas Turbine No. 2 is reported to have burned small amounts of No. 2 fuel oil in recent years, none of the other units has burned fuel oil of any type in "many" years – perhaps as long as 40 years, in the case of Gas Turbine No. 1.[10]

AEPCO has substantial fuel-oil storage at its Apache Generating Station, perhaps [redacted] gallons, according to Management.[11] All of these tanks are empty, however.

AEPCO's new LM6000, Gas Turbine No. 4, has some smaller tanks for fuel-oil storage. Those tanks are sized to [redacted] Management[12] estimates the size of those tanks at [redacted] gallons. "Minimal" quantities of diesel fuel are kept in those tanks, as natural gas has been available to fuel the unit. The oil in the tanks is used primarily to power trucks and loaders moving coal at the Station. AEPCO contacts fuel oil dealers in the area occasionally to make sure that they could re-supply these tanks quickly if necessary.

Inventory management is conducted at station storage locations. The warehouse is responsible for tracking fuel level in the tanks and use. Warehouse personnel track meter readings during each month, then "stick the tank." This process uses a graduated tool to measure the amount of oil in the tank. This physical measurement is compared to the meter readings, and any discrepancy is required to be explained.

C. Conclusions

1. AEPCO applies appropriate processes and procedures for the weighing, sampling, and analysis of coal shipments to Apache.

AEPCO's coal contracts sufficiently provide for sampling and analysis of fuel delivered to Apache. Coal weights are determined by certified scales at the coal mines, and coal qualities are determined by samples taken at the coal mines in accordance with ASTM procedures.

Several times a year, AEPCO conducts an independent analysis of its split of coal samples provided from the coal mines. No unusual trends have been observed.

2. Coal inventory variations between physically measured values and book values are fairly normal, but have been exhibiting a trend meriting investigation. (*Recommendation #1*)

AEPCO coal inventory variations between book value and physical measurements have ranged from positive 2.6 percent to negative 7.4 percent. This is not an unusual variation range, but the majority of variations have shown that physical measurements are less than book values. There are multiple sources of variations between book inventory and physical measurements, and with coal inventory now representing a more significant asset than in the past, efforts need to be made to understand the reason for the consistent trend in differences, with corrective action as necessary.

3. AEPCO has effectively administered its coal contracts.

Contracts must be managed in ways that ensure delivery of the appropriate quantities and qualities of coal in accordance with agreed upon schedules, while at the same time maintaining appropriate relationships between the Cooperative and its coal suppliers. The tasks involved require experience and skill, and good communication. AEPCO has been effective in communicating internally on all aspects of coal scheduling and deliveries on a regular daily basis. Overall, AEPCO has demonstrated that it has been effective in all aspects of coal contract administration.

AEPCO has acted appropriately to manage the various quality provisions of its coal contracts, and has taken action as necessary to monitor quality and assess penalties, when coal quality variations have warranted such actions.

4. **AEPCO acted appropriately in developing a strategy to increase certain coal inventory, in an effort to better manage the prospect of high coal transportation rates in the future.**

AEPCO's basic strategy to increase inventory of [redacted] AEPCO conducted the appropriate economic analysis to justify such strategy. The fact that coal inventory continued to build after completion of building this coal inventory did not reflect on the soundness of the basic strategy, but related to other conditions that AEPCO did not anticipate.

5. **AEPCO coal inventories have reached unacceptable levels.** *(Recommendation #2)*

AEPCO coal inventories at a level of approximately 75 days would be appropriate to deal with the increased stockpile strategy as discussed earlier, but levels in the range of 137 days, as of the end of 2009, are not acceptable. AEPCO must develop a strategy to deal with this situation.

6. **Gas-supply management is generally effective, but continued attention to performance measurement is warranted.** *(Recommendation #3)*

Judging from the materials Liberty chose to examine on a test basis and the information learned through interviews, Liberty determined that AEPCO has sufficient and not excessive resources (*e.g.*, power-purchase contracts, generating units, fuel-purchase arrangements). Liberty also observed effective management practices and mechanisms for managing gas supply. AEPCO reports[13] that, in 2006 and 2007, it did a performance assessment of power trading activities in those years. During that period, the Manager of Power Trading and Scheduling did not identify any problems in the trading program. The performance assessments were discontinued in mid-2007 because they required considerable work to gather the data and generate the report.

AEPCO also reports[14] that it uses the ACES Power Marketing member web site to review current daily gas prices, and calls ACES Power Marketing when necessary for real-time gas prices. AEPCO also monitors its purchase prices against average ICE prices for that day. These efforts are appropriate, but gas supply management involves more than just daily gas prices.

7. **Fuel oils management is appropriate.**

AEPCO has little reason to maintain any substantial amount of fuel oil in inventory; therefore, it does not. The fuel oil that it might use as back-up fuel for generation is a standard product that is widely available in the quantities that it might use. Liberty sees no reason to conduct fuel oils management any differently.

D. Recommendations

1. **Formalize a process for examining the causes of differences between physical and book inventory, and take corrective action, as appropriate.** *(Conclusion #2)*

AEPCO should form an "Inventory Team," headed by the Apache Station Manager, to understand the variations between physically measured values of coal inventory and book values. It is important to attack this problem aggressively, and formalize the Inventory Team through the following steps:

- Develop a specific membership list for the Team, representing all appropriate functions within AEPCO
- Develop a specific charter for the Team, directing it to focus on improved inventory management, including all possible causes of inventory variation, with responsibility for reporting directly to the Chief Operating Officer with specific recommendations and costs associated with corrective action
- Develop a requirement for established meetings
- Develop a requirement for publishing minutes of meetings.

2. Take immediate action to develop a plan for reducing the coal inventory level at the Apache Station. *(Conclusion #5)*

AEPCO must take immediate action to develop a plan for reduction of coal inventory level at the Apache Station. The plan must include both physical activities, as well as economic considerations, and consider all dimensions of possible action, including consideration of the following:

- Variability of load forecast levels
- Quantity flexibility options in coal contracts
- Coal resale possibilities
- Overall coal inventory storage costs
- Re-evaluation of minimum inventory targets
- Re-evaluation of maximum inventory targets.

3. Explore performance measurement for AEPCO's traders. *(Conclusion #6)*

The *Gas Hedging* chapter of this report includes a recommendation that AEPCO begin to assess its performance in forward-market purchasing. Assessment for those purchases can be as simple as plotting the hedged price against the (unhedged) market price, although more quantitative assessments, such as measuring the reduction in volatility, are possible, and are probably well within the capabilities of AEPCO's helpers at ACES Power Marketing.

For the portion (about 25 percent) of gas requirements that AEPCO buys on shorter notice, AEPCO could develop a performance-scoring system by comparing the marginal cost of buying the gas and generating the power to the cost of buying power from the grid. The same system could also be used to assess the traders' effectiveness in realizing opportunities for short-term power sales. The performance metric in both cases would be the value created for AEPCO's traders' buy/sell/generate decisions.

The primary objective of measuring performance would be to improve. Careful assessment of how well a job has been done is the first step toward doing it better. As AEPCO and the traders

get more comfortable with a performance-measurement system, it might be used to set goals for the trading function, or in the determination of compensation for the traders.

V. Gas Hedging

A. Background

This chapter addresses the following subjects regarding AEPCO's natural gas hedging:

- Strategy
- Goals
- Procedures, practices, and controls
- Performance measurement.

B. Findings

1. Historical Approach

AEPCO's[15] Resource Planning group takes load forecasts from the member co-ops and assembles them into a forecast of requirements for power. Running those forecasts through a dispatch-simulation computer model (PROMOD) then produces a forecast of power to be: (a) generated by each of AEPCO's generating units, and (b) purchased under each of AEPCO's long-term power-purchase contracts. The Resource Planning group generates forecasts that cover five-year periods, and then updates them a number of times during the year as part of AEPCO's budgeting and business-planning processes.

The generation forecasts also produce forecasts of requirements for generating fuels. Fuel prices and forward power prices within AEPCO's power-coordination area comprise inputs to the forecasting process, whose outputs include possible economy power purchases and sales, as well as quantities of fuel required, if power purchases or sales are indicated by relative price levels. This process supports the forecasting of fuel requirements by month for the next five years.

Since 2007, AEPCO has combined this forecast with gas-purchase level experience to hedge the price of the natural gas that it expects to use for power generation. AEPCO's early hedging activity focused on forward purchases of gas. Each calendar quarter, AEPCO would commit to purchase gas at an agreed price during each of the succeeding [redacted]

AEPCO's requirements for gas in the winter are much smaller than those in the summer. The Cooperative uses its storage contract [redacted]

AEPCO modified its hedging program, beginning with 2010 needs, taking advantage of its experience to date and conversations with consultants. AEPCO's Board approved these changes in June 2009. [redacted]

[redacted]

AEPCO reports that it generally finds prices in the market to be the best during [redacted]

To summarize, AEPCO lists the objective of its hedging program as [redacted]

2. Changes for 2010

Until now, AEPCO has used [redacted]

In the summer of 2009, after study with ACES Power Marketing and another consultant, AEPCO decided to [redacted]

[redacted]

[redacted]

3. Organization and Staffing[18]

Hedging falls under the responsibility of AEPCO's Manager of Power Scheduling and Trading, and his deputy, the Manager of Power Trading Services. These two individuals execute all purchases of natural gas and electric power that will occur after the next month. AEPCO has two Term Trader/Schedulers who buy gas and buy and sell power, and who schedule both gas and power, for the next day up to the rest of the month. A group of real-time Traders buy or sell, and schedule, power for the next hour.

The Manager of Power Scheduling and Trading has taken some training in physical and financial hedging. He relies extensively, however, on consulting services and advice from ACES Power Marketing. ACES Power Marketing assists AEPCO with various aspects of its trading and hedging activities, and provides daily reports on market conditions, advice on particular strategies, and certain execution and execution-support services. ACES Power Marketing's on-site representative manages entry of AEPCO's trades into the transaction-tracking system, and assists in approving supplier invoices for payment.

ACES Power Marketing also assists with administrative aspects of AEPCO's hedging program. ACES Power Marketing assists with the negotiation of all contracts, conducts all credit analysis for existing and potential trading counter-parties, and monitors AEPCO's credit exposures with respect to its counter-parties. ACES Power Marketing also assists AEPCO in administering its authority matrix for entering into agreements and transactions.

4. Transaction Tracking

AEPCO uses deal tickets to record natural-gas and term power transactions entered into by its traders. The real-time power traders enter their transactions on MS Excel™ spreadsheets. ACES Power Marketing's on-site representative gets the deal tickets for entry into the transaction-tracking system. The real-time traders' spreadsheets upload directly into the system.

ACES Power Marketing uses the Allegro transaction-tracking software. Each of ACES Power

Marketing's clients, both owners and customers, has a data base for its transactions. ACES Power Marketing's on-site representative ensures that all of AEPCO's transactions are entered into the system. She also uses the data in the system in approving supplier invoices for payment.[19]

5. Policies and Procedures[20]

An AEPCO Transaction Authority Matrix specifies which officers can approve commitments, and which commitments must go to AEPCO's Board of Directors for consideration. Separate limits apply to the amount of money committed and to the term (length) of commitments. AEPCO's Board of Directors has approved the Transaction Authority Matrix.

AEPCO also has documented policies and procedures for natural gas trading (Natural Gas Trading Authority Practices) and for power trading (Electric Power and Transmission Trading Practices). Subjects covered in those policies and procedures include the following:

- Who has authority to execute transactions
- The commodities and products that can be transacted
- The authorized lead time and term for each transaction
- The authorized maximum price and volume
- Counterparty contract and credit requirements
- The process for approving new commodities, products or locations
- Other relevant factors associated with due diligence in authorizing transactions to be executed.

AEPCO Trading Sanctions define the procedures for addressing non-compliance with electric power and transmission and natural gas trading practices. These sanctions address the consequences of non-compliance. The Trading Sanctions also include general guidelines for determining appropriate disciplinary action, to ensure disciplined and consistent enforcement of the policies and procedures. The ACES Power Marketing on-site representative has responsibility for monitoring compliance with the trading practices limits and for reporting all non-compliance incidents to appropriate AEPCO staff and senior officers. Violations are reported to the violator's supervisor, and to that person's supervisor. AEPCO updates the Natural Gas Trading Authority Practices and Electric Power and Transmission Trading Practices as necessary. Their most recent versions bear a date of March 29, 2010.

C. Conclusions

1. AEPCO's objective for its hedging program is clear, but the Cooperative does not conduct structured measurements of effectiveness in meeting that objective. *(Recommendation #1)*

AEPCO's objective for its hedging program is [redacted] Liberty understands that the member cooperatives, through their representatives to AEPCO's Board of Directors, understand and support this objective.

While the objective is clear, Liberty did not find any evidence of effort by anyone to assess whether the objective was being met. Illustrations of the effect of hedging programs on price

stability and price levels were contained in the materials prepared by ACES Power Marketing for AEPCO when it was considering whether to engage in hedging, but Liberty found no assessment of program results after AEPCO had decided to engage in hedging. This area needs attention.

2. AEPCO has adopted effective hedging strategies, and uses appropriate instruments to effectuate them.

[redacted]

3. Hedging personnel are adequately qualified.

The qualifications of AEPCO's employee, the Manager of Power Scheduling and Trading, who conducts hedging activities, typify what Liberty has seen at other utility organizations. Such individuals have often, as in this case, learned their trade primarily by practicing doing it. The AEPCO incumbent has also attended some short courses on physical and financial hedging. Often the principal benefit of such courses is to learn the terminology of trading and hedging.

AEPCO's other asset in this area is its relationship with ACES Power Marketing. With its 17 full members and 30-odd clients, ACES Power Marketing has a sufficiently solid and sophisticated clientele that it can attract and retain highly-qualified people, and support expensive and sophisticated systems. In its hedging activities to date, AEPCO has relied extensively on ACES Power Marketing's expertise in designing the program, and on its sophisticated capabilities and tools in managing it. AEPCO's members and customers should feel confident that its hedging program "is in good hands."

4. AEPCO's transaction-tracking capabilities and systems are first-rate, but have not been audited regularly. *(Recommendation #2)*

AEPCO's principal asset in this area is its relationship with ACES Power Marketing. The transaction-tracking software used is the industry standard, and the controls on this activity exhibit the expertise that ACES Power Marketing brings to the relationship.

As a routine matter, Liberty believes that controls on trading should be periodically examined by Internal Audit. We have no reason to expect that Internal Audit would take issue with any of the processes or flows. However, because trading and hedging expose an entity to large losses, they should be examined periodically.

6. AEPCO applies appropriate risk-management policies and procedures.

AEPCO has trading authority policies and procedures, which also cover hedging, for both electric power and natural gas. These policies and procedures cover all important areas, and reflect expertise in their construction. Instruments and processes are well covered and tightly

prescribed.

D. Recommendations

1. Assess hedging program results. *(Conclusion #1)*

At a minimum, AEPCO should conduct annual assessments to determine whether the hedging program is meeting its stated objective: [redacted] Such an assessment can be as simple as plotting market prices versus hedged prices, and looking at the resulting graph.

Many utilities also use assessments of their hedging program to try to improve performance. Such an effort can require more sophisticated analytical techniques and capabilities, but any such effort would be well within ACES Power Marketing's capabilities. AEPCO should discuss the subject of program assessment with ACES Power Marketing, and select an analytical approach it finds comfortable. Results should be discussed with AEPCO's management and Board, along with analytically-supported recommendations for adjustment if appropriate.

2. Provide for periodic Internal Audit review processes and systems for tracking of transactions at AEPCO. *(Conclusion #4)*

Liberty sees no deficiencies in the structure of the control processes that AEPCO has in place. Nevertheless, good practice indicates that Internal Audit examine those processes to assure AEPCO's management and members that the processes are sound.

VI. Power Transactions

A. Background

AEPCO owns the Apache station, whose generating units have a net capacity of about 558 MW. AEPCO relies predominantly on its own generation to supply members' loads, supplemented by market power purchases. Its purchases fall into three principal categories:

- Long-term contracts from various sources to supplement AEPCO's requirements for capacity and for energy
- Short-term purchases from regional power markets, when AEPCO is able to buy on a real-time (hourly) basis at a delivered price lower than its marginal cost to generate with its more expensive units or to take from its purchase contracts
- Shorter-term purchases of market power that may be acquired to replace AEPCO generation during maintenance outages or at peak load times.

AEPCO has also made long-term sales of capacity and energy that were in excess of its members needs in the past. Particularly notable among these arrangements is a 20-year, 100 MW contract with Salt River Project ("SRP"). This SRP contract expires on December 31, 2010.

B. Findings

1. AEPCO Power Purchases

a. Power Purchase Summary

The next table shows AEPCO's total power purchases.[21] The Cooperative's firm purchases are for generating capacity, as well as for related energy when it is economic as compared to AEPCO's own generation or other market alternatives. Short-term purchases are made on an hourly basis, for one to three days, or for 15-30 days or more to provide energy during a maintenance outage for the Cooperative's own generating units. Total power purchases have ranged from about $35 to $49 million annually during the four-year period from 2006 through 2009. [redacted]

[redacted]

2. Firm Purchase Contracts

The next table[22] provides more detailed information on AEPCO's contracted firm power purchases during the four-year period from 2006 through 2009. [redacted]

The other firm purchased power contracts shown in the table resulted from AEPCO market-power contract solicitations performed starting in 2001. The solicitation processes are discussed further below.

[redacted]

3. Estimating Power Requirements

AEPCO develops plans for power resources using standard software packages accepted in the electric industry for these purposes. The Cooperative uses PROMOD software to model load requirements and power supply resources for budgets, for FPPAC forecasts, and for financial

forecasts of up to five years. AEPCO also uses PROMOD for day-ahead, weekend, and maintenance outage scheduling of power resources. AEPCO uses another widely accepted product (Strategist power planning software) for long-term and resource expansion planning.

Load forecasts provide a foundation around which AEPCO forms power resource plans. Each AEPCO member prepares its own load forecast, with some assistance and coordination from AEPCO. New load forecasts are prepared every three years as part of a forecasting cycle designed to meet RUS requirements. These forecasts are updated annually in the years between establishing new planning baselines. An AEPCO manager uses the forecasts from the individual members, and factors in an econometric forecast. The University of Arizona prepares the latter. Twenty-year load forecasts are prepared for each member and approved by the member boards for each three-year cycle. The AEPCO Board of Directors approves the aggregate load forecasts for resource planning purposes.

The customers of the six primary members are mostly residential, with some small commercial customers but very few industrial customers. On the other hand, resource planning for the system requirements has changed drastically in recent years as AEPCO's largest all-requirements members have become partial-requirements members. Traditionally, all six of AEPCO's distribution cooperative members were all-requirements customers. First Mohave, then Sulphur Springs, the largest and second largest members, switched to partial requirements. Currently Trico, the third largest member, is in the process of becoming a partial requirements member. Partial requirements members are allocated a slice of AEPCO's power supply resources in accordance with their June 2001 load requirements as a percentage of the AEPCO total. The partial-requirements members are responsible for arranging their own capacity and energy requirements above the allocated levels. Partial requirements members may schedule and purchase energy from AEPCO in any amount up to their allocated limit.

They may schedule and purchase AEPCO power and sell part or all of it in the marketplace, if they so choose. The partial requirements members schedule energy supply through AEPCO, but only to their limits. They purchase the remainder from the power markets. [redacted]

4. AEPCO Power Solicitations

AEPCO has conducted several competitions for power supply resources since 2001. In August 2001, AEPCO issued a Solicitation for Proposals seeking baseload resources and May-to-September peaking resources for the years 2003 through 2010. The RUS has required competitive solicitations for new generating resources. During the preceding several years, generating capacity in the Southwest region had become overbuilt, resulting in significant excess generating capacity, which AEPCO believed would make purchased-power contracts less expensive. However, 2001 turned out to be a year of turmoil in regional power markets, causing

AEPCO to terminate the process. During this time period, Mohave, AEPCO's largest member, became a partial requirements customer. The California and Southwest power markets became dysfunctional during this time period. The Enron meltdown occurred in November 2001, causing further turmoil in the national and regional power markets.

AEPCO re-bid its solicitation in November 2002. Prior to this second solicitation, Sulphur Springs, AEPCO's second-largest member, had given notice that it would become a partial requirements customer. AEPCO's need for acquiring future base load power resources thus became substantially reduced.[25] The solicitation requested proposals for only peaking resources for May through September for the years 2003 through 2007. [redacted]

AEPCO's power supply resource modeling and planning identified a need for additional power supply resources for 2008 and beyond. In 2003, a solicitation for proposals requested baseload, medium-term, and peaking options. The requested starting date for contracts was 2008; a minimum of three years was requested, and AEPCO noted that the years 2008 through 2014 were to be of primary interest. AEPCO was interested in a diversity of suppliers, and considered transmission constraints also an important factor. All bidders were merchant power entities that had available capacity for sale in a market that continued to be over-supplied. AEPCO evaluated the proposals against each other, and compared them with the all-in costs of a new LM – 6000 gas turbine. The proposals were found to be significantly less expensive. [redacted]

In 2005 and 2006, AEPCO identified the need for additional baseload and peaking power supply resources. The Southwest Public Power Resources group ("SPPR") had been formed by this time, with AEPCO as a member. The SPPR includes municipal utilities, cooperatives such as Sulphur Springs, tribal power authorities, electric districts, and irrigation districts. Starting in 2006, SPPR has performed four joint solicitations for those of its members that elected to participate in each. The group initially estimated its long-term power supply needs as falling in the range of 1,300 MW. That amount has fallen substantially in recent years. AEPCO

participated in the initial SPPR power supply solicitation in 2006. That solicitation focused on the shorter-term requirements of the group. In April 2007, six of the SPPR participants signed peaking contracts with selected bidders. [redacted]

In 2008, the SPPR issued a solicitation for bids for long-term power resources. The resulting proposals consisted mostly of bids for power supply from the development of new generating resources, which were generally unattractive to the tax-exempt public power group. No contracts resulted from this solicitation. The economic downturn starting in 2008 also significantly reduced the estimated power resource needs of the SPPR group. Another SPPR group solicitation for proposals for 500 MW of long-term power resources was issued in the summer of 2009, and an agreement was reached with a power supplier for a joint contract. However, with the continuing economic downturn, the SPPR group believed that the resource needs of the group participants had been reduced to far below the 500 MW requested. The solicitation was re-bid in early 2010, and the SPPR group has recently shortlisted three bidders for 220 to 280 MW starting in 2015 for contracts with a 25-year term. [redacted]

5. Off-System Contract Sales

[redacted] AEPCO is allocating the generating capacity from the Mesa and SRP contracts as they expire to its six 2001 all-requirements members. These power-sales contracts were signed quite some time ago, when AEPCO had excess power supply resources that were available. The Cooperative's resource modeling and planning indicate that it does not have long-term resources available for sale currently or in the future.[30] As result, AEPCO has not attempted to extend its contracts with SRP or to offer term contract sales in regional power markets. In fact, the Cooperative says that it does not normally make power sales beyond two days in duration, and that it relies primarily on real-time hourly sales when selling any excess resources.[31]

6. Trading

a. Day-ahead Scheduling and Trading

AEPCO's Power Trading desk prepares a schedule of its upcoming resource commitments on a daily basis. The day-ahead schedule seeks to meet most economically AEPCO's system requirements for the next day (for the next 2 or 3 weekend and holiday days each Friday). AEPCO uses the PROMOD dispatch modeling system to aid in determining its scheduling for the next day, week, or month. However, almost all scheduling takes place on a day-ahead or weekend basis. The day-ahead schedulers focus on this form of scheduling.

The day-ahead scheduler must first determine the electric loads that are expected during the following 24-hour period. In addition to the load forecasts included in the PROMOD model, the

day-ahead schedulers review the hourly load history of recent days, in order to determine load levels for each hour at the temperatures experienced on each day. This recent load information gives the scheduler a best "read" as to actual loads that will occur for AEPCO at specific temperature levels.

AEPCO faces some complicating factors that make the determination of the level of power resources to schedule more difficult. Three of AEPCO's members provide pre-schedules that AEPCO must consider in making its day-ahead schedule. SRP may schedule from zero to the full 100 MW under its purchase contract. [redacted] Such potentially wide swings in pre-scheduling levels means that the scheduler has to make a best estimate of the SRP, Mohave and Sulphur Springs pre-schedules in order to complete the AEPCO schedule and provide it to the ICE between 5:15 and 6:45 AM. The AEPCO schedulers note that Mohave and Sulphur Springs tend to pre-schedule toward the maximum end of their range, as they cannot schedule additional resources on short notice. If these partial requirements members pre-schedule more power resources than they actually need, they may sell the excess in the power markets, if they so choose.[32]

On the power supply resource side, the scheduler checks with Apache to determine any updates for minor maintenance or problems that may cause any of AEPCO's generating units at Apache to be partially or fully unavailable during the following 24-hour period. The scheduler also communicates with the real-time traders to compare information and determine if any market-affecting resource shortfalls or major market outages have occurred. The scheduler then uses daily gas price and power market forecasts from ACES, as well as ICE market information, to determine the prices for components of AEPCO's power resource "stack" for the next day. The next table[33] shows a roughly estimated economic dispatch stack for AEPCO for July 20, 2010. The lowest cost resources are at the bottom of the stack; the pricing of each resource increases from the bottom to the top of the stack in ascending order. AEPCO will acquire assets in ascending order until the projected electric load for each hour is met.

AEPCO Rough Economic Dispatch Stack, July 20, 2010

Power Supply Resource	*Size (MW)*	*Marginal Cost per MWH*
[redacted]	[redacted]	[redacted]

The WAPA power purchases and the two Apache coal units will be scheduled first, as the generally least expensive power resources. On this particularly hot summer day with high air-conditioning loads, the scheduler bought 50 MW of "super peak" power to supplement AEPCO's

other resources during the hottest hours (1 PM through 8 PM). On a high peak day, buying power on a real-time, hourly basis for these hours may be difficult to execute or very expensive, causing the scheduler to buy 50 MW for the super peak hours that were available one day in advance for a reasonable price.

On more normal days that are not near system peaks, decisions are made each day in scheduling the resources in the stack above the coal units. The AEPCO schedulers usually make decisions from among four resource options to fill out the top of the resource stack on most days. [redacted] According to AEPCO, market purchases may be more attractive than any of the gas-fired options, or may be placed in the middle, or even could be the most expensive option, if demand in the California and Southwest markets is high.[34] The resources at the very top of the stack are the most expensive, and rarely used, except in emergency situations or to provide required spinning reserve on peak days.

The scheduler then executes the day-ahead plan by making the power purchases and sales required to roughly meet the AEPCO load, and including these transactions in the day-ahead schedule, which is submitted to the ICE by 6:45 AM on the morning before the first hourly transaction at midnight, beginning the next 24-hour period.

7. Real-time Trading and Economic Dispatch

The results of the day-ahead schedule also go to AEPCO's real-time desk to manage the economic dispatch on an hourly basis. AEPCO has a team of real-time traders; one or two are on duty at all times. The real-time traders enter into hourly transactions for purchases and sales, if they are economic compared with AEPCO's power supply resource stack. The real-time desk constantly monitors the system loads, the resources operating to meet the loads, and looks ahead to determine changes in load, resources and potential opportunities in the upcoming hours. For each hour, the energy marketer assesses the dispatch order and compares to the costs of market resources (from ICE real-time market information) available for purchase with AEPCO's incremental generating costs, and will make hourly purchases from the market when economically advantageous. The real-time trader "shops the market" to fill in requirements in upcoming hours. AEPCO's real-time traders usually fill these needs with two-hour power purchases. Another option is to buy strips of several hours of power from the same source. However, since the market currently tends to have ample hourly availability, waiting for better pricing for purchases many times can be more economic than buying several hours or up to a whole day in advance.

The real-time traders have several counterparties that they have confidence can provide the resource timing, volume, and price required to meet AEPCO needs. In other words, the traders may have specific "go-to" counterparties that they know can deliver the timing, volume and price required upon short notice. The real-time traders note that there are only a handful of sources where 50 MW, 100 MW, or even 150 MW may be purchased quickly if AEPCO's

biggest unit goes off-line unexpectedly.[35] AEPCO real-time traders may also be required to make real-time purchases or sales if the SRP, Mohave or Sulphur Springs pre-schedules have changed after the day-ahead schedule was submitted to ICE by the day-ahead scheduler.

8. Term Trading

AEPCO has historically made most of its power purchases that are not real-time or day-ahead trades for two or three days, when scheduling power supply requirements for a weekend or holiday. Liberty reviewed AEPCO's complete listing of power purchases and sales that were of greater than one day in duration but less than the long-term contracts that were described above. These purchases and sales of more than one day may be considered "term trading" for AEPCO.

Liberty reviewed the transaction listings from September 2005 until April 2010. As AEPCO has described, the vast majority of the transactions were for two-day purchases to cover weekends, as well as a small number of three and four-day purchases to cover holiday weekends. AEPCO notes that most, if not all of the transactions were the results of pre-scheduling for two days at a time. AEPCO pre-schedules on Thursday for Friday and Saturday, and pre-schedules on Friday for Sunday, Monday and holidays. These trades are normally conducted on ICE software. AEPCO usually contacts multiple counterparties from its established credit list and requests verbal bids for this weekend power. Depending upon the available credit with counterparties, volume, price and receipt point limitations, AEPCO may purchase from one or two suppliers for these weekend needs.[36]

The remaining AEPCO term transactions during this time period were identified and discussed with AEPCO to determine the particular need that was filled by these purchases. Some of the purchases were for 15 to 60 days in duration. Most of the term purchases were arranged to plan for maintenance outages or major equipment overhauls at AEPCO's Apache generating complex. AEPCO notes that "planned major overhaul outages are normally covered by purchasing some portion of power months ahead of the outage." AEPCO normally buys 50 percent to 75 percent of the power needed during the overhaul. AEPCO did not buy any power for these purposes in 2009 because of indications that market prices would be lower, and that AEPCO would consequently have reduced takes from SRP, Mohave and Sulphur Springs. The reduction in energy taken from these entities allows AEPCO to use more of its own generation to cover outages.[37]

The following paragraphs provide examples of the AEPCO term purchases, which were not numerous. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

9. ACES Services

ACES provides services to its owners, who are mostly generation and transmission cooperatives. AEPCO is a member and an owner of 6.25 percent of ACES. AEPCO relies on ACES for a number of services related to power and gas markets, energy trading and risk management. ACES maintains one full-time employee at the AEPCO offices to perform many of its service functions.

ACES' most important services provided to AEPCO relate to risk management. ACES provides an independent monitor function for all of AEPCO's gas and power transactions and trading operations. ACES oversees the middle and back-office functions of AEPCO's trading operations. AEPCO's schedulers/term traders have printouts from the ICE system that includes the details of their term transactions. The schedulers then fill out an AEPCO deal ticket and timestamp the ticket. Later, an ACES employee checks the transaction information and enters the deal information into the Allegro transaction system operated by ACES for all of its clients. ACES' Allegro system maintains the transaction records in its system separate from AEPCO, providing a risk management function. ACES also checks and enters AEPCO deal tickets for transmission transactions.

ACES also monitors and separately records AEPCO's real-time transactions. Real-time trades, including the real-time transaction details and the transaction tags, are captured in AEPCO's Minnesota Consulting Group ("MCG") software as they are made. The real-time traders also record their transactions in a separate MS Excel™ spreadsheet for each 24-hour period. AEPCO's nighttime traders check the transactions in the spreadsheet against the transactions in the MCG software to ensure that they are consistent internally. The spreadsheet is then e-mailed

to ACES; it includes 24 hours of trading information. ACES checks the transactions, and enters them into its Allegro system. ACES will also follow up on specific transactions with the traders to ensure that they are correctly recorded.

Another function performed by ACES is that of counterparty credit reviews. The ACES home office maintains financial analyses of numerous trading counterparties, and updates them on an ongoing basis. ACES provides a "Trading Restrictions Report" to AEPCO and each of the traders daily. This report provides credit limits for each potential trading counterparty based on the credit standing of each.

ACES provides a significant amount of market information and analysis to AEPCO. For instance, ACES provides a "Power Report" that includes forward price curves that estimate future power pricing. Forward capacity curves are also provided. ACES prepares a "Daily Report" of market information for the ICE markets (Palo Verde, Four Corners, Mead, and California SP – 15). ACES provides a "Previous Day Recap" that summarizes the previous day's market activity. ACES provides an "Energy Price Outlook" that is a weekly update of national energy markets. ACES also provides daily e-mail energy market updates which are overviews of all U.S. energy markets.

ACES also provides other services to AEPCO that aid the trading operations. ACES performs mark-to-market analyses that value positions held by AEPCO for financial statement purposes. ACES also negotiates the standard ISDA contracts for AEPCO that are signed with each counterparty and used in each transaction. ACES' consulting arm is available to AEPCO on an ad hoc basis.

Finally, ACES provides scheduling for Anza, which is located in California. ACES has the software packages that are needed to interface with the California ISO because it has a number of clients in California. Because AEPCO can only wheel a portion of Anza's requirements to the member, ACES schedules supplemental power for Anza in California.[39]

10. AEPCO Trading Practices

AEPCO established and has regularly updated its "Electric Power and Transmission Practices" since at least 2004. The most recent update of these practices is dated March 29, 2010. The Trading Practices establish definitions and guidelines for AEPCO's trading operations, as summarized below.

The Trading Practices define:

- Who has authority to execute transactions
- The commodities and products that may be transacted
- The authorized lead time and term for each transaction
- The authorized maximum price and volume (as defined in exhibit A to the Trading Practices)
- Counterparty contract and credit requirements
- The process for approving new commodities, products or locations

- Other relevant factors associated with due diligence in authorizing transactions to be executed.[40]

The associated power trading Authority Matrix, most recently revised May 1, 2008, sets maximum transaction limits for five levels of employees (trader to CEO) regarding total trade dollars, total megawatt-hours, on-peak and off-peak and total megawatt capacity, term of the transaction, and lead-time for each transaction.

AEPCO also has a "Trading Sanctions" policy dated May 25, 2007, as well as a code of employee conduct. The Trading Sanctions define the procedures by which violations of the trading practices described above will be addressed. The Trading Sanctions assist in ensuring compliance with the trading practices and facilitate specific risk management practices. The ACES trading control specialist is responsible for monitoring compliance with the trading practices limits and reporting all non-compliance incidents to the appropriate AEPCO staff and the Risk Management Committee.[41]

11. FPPAC Internal Audit Review

AEPCO internal auditing performed an audit of the AEPCO "fuel bank" for the entire calendar years of 2007 and 2008. The audit was initiated in March 2009, and concluded with a report that is dated June 30, 2009. The AEPCO fuel adjustment mechanism had been re-instated as of September 1, 2005. A previous version of fuel adjustment mechanism was discontinued in 2001 with the restructuring of AEPCO. Previous to the internal audit, the Cooperative says that the only other audits of the fuel mechanism since September 1, 2005 were performed by outside auditors as part of financial statement audits.

The primary observation of AEPCO's internal audit was that several errors were identified in the Fuel Adjustor Mechanism ("FAM"), a spreadsheet maintained by the AEPCO financial services department for the period of January 2007 through December 2008. The errors caused the revenue of AEPCO to be overstated by a net $833,035 over the two-year period. On May 5, 2009 the AEPCO accounting department processed an adjustment journal entry for the same amount with a posting date of December 31, 2008. The AEPCO independent auditor's report and financial statements audit for 2008 included this adjustment.

The internal audit report enumerated numerous errors and 15 observations that were made by the audit, which each required a management response. The report enumerated errors in coal expense, legal expense, gas fuel, purchased power, wheeling expenses and non-class A sales for resale. The revenue of AEPCO is overstated by $98,659 in 2007 and again by $734,376 in 2008. The errors in the FAM that required correction by the accounting adjustments were caused by a combination of several factors, according to the audit report:

- Missing transactions in the KOB1 report generated by AEPCO's SAP accounting software, most likely because internal orders were not assigned to that report. The KOB1 report is the primary source of data used by the AEPCO financial services department to prepare the FAM

- Journal entries posted by the AEPCO accounting department for the month of December 2008, after the financial services department had already processed the KOB1 report for that month and without their knowledge
- Data entry errors in the FAM
- Errors in formulas of the FAM.

These errors were not identified by AEPCO until the internal audit report, because full reconciliations of the entries in the FAM versus the AEPCO general ledger had not been performed. Internal Audit recommended that the financial services department reconcile the year-to-date total amounts of several components of member fuel and purchase costs against the corresponding general ledger in order to identify any errors on a monthly basis, and to have them corrected before the FAM report is filed with the Arizona Corporation Commission.

The following is an example of one of the 15 observations in the internal audit report, and the management response:

> *The reconciliation of the GL records against FAM showed that several legal expenses for the period of January to October 2007 were not deducted in this report, causing the Member Fuel and Purchased Costs amount to be overstated by $43,550 for the year of 2007.*

The corresponding management response by AEPCO to this observation was as follows:

> *The process of calculating and reconciling the FAM has been updated to include cross-checking of the account balances derived from the KOB1 report with additional resource documentation provided by the purchase power and accounting departments. These source records include energy accounting documents and purchase power and transmission reports. In addition, as part of the FAM calculation, the senior financial analyst now completes a spot check comparison to individual GL balances related to coal and legal expenses in SAP.*
>
> *Financial services and accounting personnel have developed a standardized KOB1 report format which includes additional fields required to provide a complete record of information needed by both departments. The standard format ensures that both departments use the same parameters for gathering data and reporting purposes.*
>
> *Management and staff have also worked to improve communication and information flow between financial services and accounting personnel. Accounting staff notify the senior financial analyst by e-mail of unusual transactions affecting the accounts related to the FAM calculation. In addition, financial services and accounting personnel have increased our knowledge and understanding of how transactions within SAP affect the calculation of the FAM.*
>
> *These process changes were effective July 2009.*

The foregoing response or portions of it were used in the management responses for 14 of the 15 observations made in the audit report.

C. Conclusions

1. AEPCO has reasonably effective practices and operations for scheduling and dispatching power supply resources, but can suffer from not receiving timely information from some large members. *(Recommendation #1)*

Liberty's review of AEPCO's scheduling, real-time dispatch, and trading functions determined that the Cooperative effectively manages and operates these key functions. Operations take place under clear lines of responsibility, established operating routines, and a qualified work force. AEPCO effectively schedules and dispatches its own plants and long-term contracts, while regularly taking advantage of hourly market opportunities to buy economic purchased power to displace its own generation and purchase contracts. Both the day-ahead and real-time operations effectively use market information in their decision-making. AEPCO also has performed (in 2006) a year-long trading and transaction performance scoring method; however, it was determined that administering the program did not add sufficient value.

AEPCO does have difficulty in scheduling the resource requirements of its large member customers. Three of AEPCO's members provide pre-schedules that must be factored into AEPCO's daily day-ahead schedule. AEPCO says that the pre-scheduling information is not received in time to accurately schedule AEPCO's total needs. Since Salt River Project, Mohave and Sulphur Springs have very wide minimum and maximum take levels from AEPCO, such potentially wide swings in pre-scheduling levels means that the inability to "read the minds" of these members could result in daily over-supply or under-supply situations. The AEPCO scheduler has to make their "best estimate" of the SRP, Mohave and Sulphur Springs pre-schedules in order to complete the AEPCO schedule and provide it to ICE between 5:15 and 6:45 AM.

2. AEPCO's power trading operations have established effective processes and methods for arranging economic term purchases of power.

AEPCO has consistently expressed to Liberty that it has arranged "term purchases" (more than one day but less than one year) for two purposes: a) to purchase blocks of power needed for weekend days; and b) to arrange power for power plant maintenance and overhaul outages. Liberty's review of all of the AEPCO "term trades" from September 2005 to early 2010 confirmed that these are the types of trades that were arranged during the period. AEPCO primarily has arranged power trades on an hourly, real-time basis, and also under its long-term contracts. Liberty concludes that AEPCO effectively uses market power information to analyze the opportunities in the power markets to make economic purchases on day-ahead, real-time and term bases.

3. AEPCO's processes for soliciting long-term power resources have been thorough and effective in not over-committing AEPCO to either owned power resources or long-term contracts.

AEPCO has solicited proposals for power supply resources several times since 2001. Since 2006, AEPCO has been part of the SPPR buying group for power supply resources. [redacted] These processes have taken advantage of the overbuilt power supply markets in the Southwest region to the benefit of AEPCO members. The solicitation and evaluation processes demonstrate that the purchase contracts were superior options at that time to either building more generating capacity or buying through other available purchase contracts.

AEPCO's decision to join and participate in SPPR power supply solicitations since 2006 greatly increases its buying leverage and reduces asset ownership risk. Eighty-nine percent of AEPCO's future member load will be for partial requirements customers; therefore, the future need for additional power supply resources will be small. The SPPR provides a good mechanism to leverage AEPCO's smaller needs through an association of other public power entities.

4. **AEPCO's internal audit reports show an insufficient attention to detail regarding the FAM that has only recently been resolved. AEPCO also lacks written processes and procedures for calculating and reconciling FAM information and reports.** *(Recommendation #2)*

The lack of close attention to detail and the failure to reconcile accounts for the FPPAC are significant problems that require attention to assure continued confidence in the accuracy of fuel recovery. AEPCO has made significant and appropriate changes in its processes regarding the fuel filings. These changes should minimize or eliminate the errors experienced in 2007 and 2008. AEPCO's internal audit department has reviewed each quarterly FAM process since the discovery of the errors, and should continue to do so. The Commission must have a sound basis for confidence in the FAM information, which should make verification that processes have improved sufficiently a high priority for AEPCO and its internal auditors.

D. Recommendations

1. **Require partial requirements members and SRP to make timely submissions of pre-scheduling power requirements to AEPCO.** *(Conclusion #1)*

For Mohave, Sulphur Springs, SRP, or other partial requirements members to not provide their daily power requirements pre-schedule to AEPCO on a timely basis could have significant consequences for other members. AEPCO should immediately demand that pre-scheduling information be provided by a specific time that allows adequate time for AEPCO to include these requirements in its scheduling. AEPCO should not take responsibility for the consequences of a partial member's inattention or inappropriate action regarding scheduling. AEPCO should also undertake an analysis of the degree of past economic harm resulting from untimely submission, in order to determine whether the magnitude of harm is sufficient to warrant adjustments among members to address any such harm.

2. **Provide proof of the effectiveness of the new FAM processes to the ACC. Complete written processes and procedures for FAM calculations as soon as possible. Increase the frequency and depth of internal audits conducted at AEPCO, with more detailed focus on the fundamentals of fuel and energy procurement and management.** *(Conclusion #4)*

AEPCO's plans to document the processes and procedures for the FAM filings should be completed as soon as possible. AEPCO's current plan to complete these procedures by mid-2011 is not sufficiently prompt, they should be significantly accelerated to ensure that the proper processes are fully documented and not subject to the availability or specific knowledge of individual employees. AEPCO should then demonstrate to the Commission that its changes do in fact address all causes of its 2007 and 2008 filing errors and that it is taking efforts to verify their sufficiency.

Fuel bank audits as described to Liberty have not been conducted on a frequent enough basis, and have not been of great depth, given the high costs and risks associated with fuel and purchased power. Internal Audit should take direct and primary responsibility for establishing the frequency and scope of a more intensive fuel and energy audit program. If necessary, Internal Audit should have exclusive responsibility for identifying the sources of any outside assistance required to conduct them. Internal Audit is a comparatively small group that may not have sufficiently broad experience with fuels and energy operations to examine it in proper detail.

VIII. Engineering Analysis/Plant Operations

A. Background

Liberty conducted an engineering analysis of AEPCO's assets, focusing on the generating units, which form the core of those assets. Much of Liberty's work focused on the Apache Plant ("Apache"). Liberty examined station performance, operations, maintenance, and capital improvements. Liberty reviewed existing maintenance practices, examined how AEPCO documents them, and reviewed management controls to ensure proper implementation and execution of those practices. Liberty also reviewed plant outages and conducted a review designed to determine the "used & useful" nature of rate-base assets. Liberty's review included a physical inspection of the Apache Plant and interviews with the personnel responsible for managing key functions at the plant.

This report presents the results of Liberty's review, categorized into the following subjects:

- Station performance
- Outages
- Maintenance
- Capital additions and rate base
- Facility review

B. Findings

1. Organization

All of AEPCO's senior managers are employees of AEPCO. Otherwise, nearly all staff are Sierra employees, with most located at the plant. Several individuals from Sierra's financial, safety, and environmental functions are also located at the plant.

The general organization structure is somewhat "cleaner" than that of SWTC,[42] where there is more intermingling of employees on the organization chart. Liberty saw no evidence that this hybrid structure impedes overall effectiveness in any way. In practice, Liberty observed that AEPCO operates as a single organization, regardless of the role of Sierra in employing most personnel. There may be two organizations on paper, but Liberty found only one in practice. Accordingly, Liberty found no reason for criticism of the organization's design, functioning, and effectiveness.

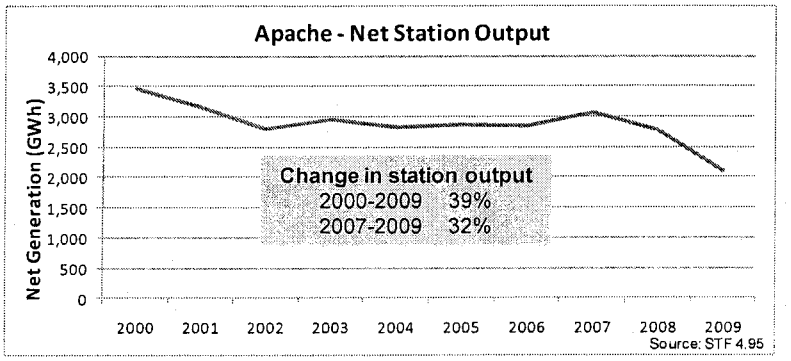
2. Generating Units

The bulk of the generation at Apache comes from Steam Units 2 and 3, which are 175 MW base load coal-fired units. Steam Unit 1, a gas-fired boiler, operates in combined-cycle with Gas Turbine 1 to provide a net 85 MW of peaking capacity. The remaining three gas turbines produce 129 MW of peaking capacity.

Gas Turbine 4 is relatively new, but the other units are aging, with the two base load units over 30 years old and Steam Unit 1 over 40 years old.

3. Station Performance

Liberty evaluated Apache performance, specifically as measured by availability, capacity factor, and unit heat rate. In 2009, Apache suffered a precipitous drop in output. Station management believes such performance was an anomaly; unfortunately, there are indications that more troubling forces are at work.

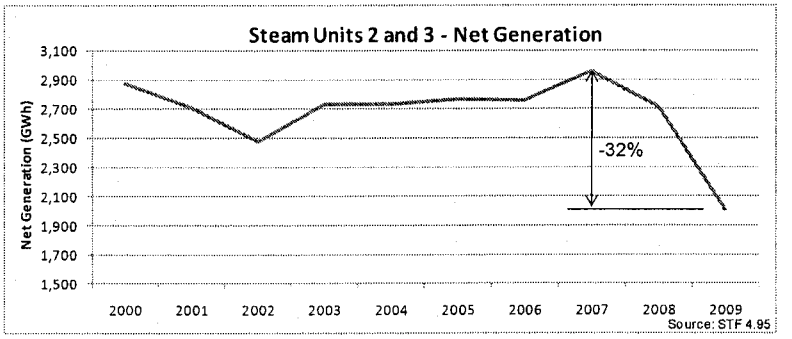


In any event, net station output is down nearly 40 percent, between 2000 and 2009, as shown on the accompanying chart.[43] At the same time, Steam Units 2 and 3, both of which performed poorly in 2009, now account for well over 95 percent of the station output. If these trends continue, and there are indeed reasons to believe they might, the future of this station could be in jeopardy.

a. *Steam Units 2 and 3*

The data and supporting analysis suggest that a transition is taking place. Specifically, the two flagship units, ST2 and 3, are evolving from base load units to, at best, intermediate units. In 2009, this was prompted by higher dispatch costs and a lesser level of economic competitiveness. At the same time, availability was well below expectations, dealing a double blow to station performance.

Steam Units 2 and 3

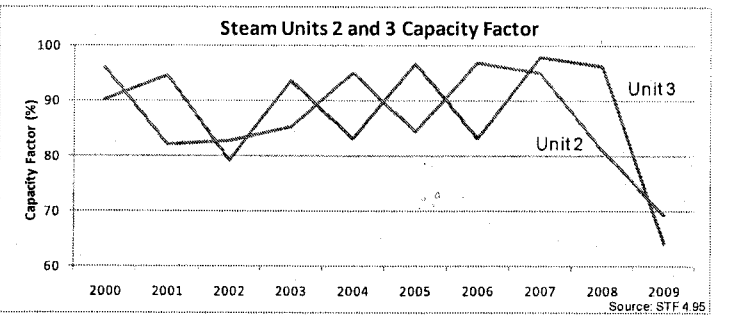


The base load coal-fired units are the key producers at Apache Station. It is from these two units that the great majority of the station's output will come. For many years, their performance was excellent, but a sharp drop was experienced in 2009. In analyzing the drop, one must emphasize that at least two major forces were at work. First, availability dropped sharply and outages were experienced on a previously unheard of frequency. Second, when available, the units were dispatched at rates well below their historic levels.

The accompanying chart illustrates the sharp drop in output in 2009. After rather consistent performance for many years, there was a 26 percent drop from 2008, and 32 percent versus 2007.

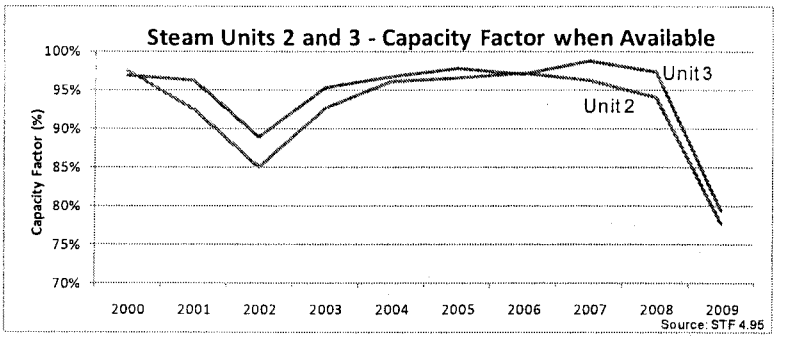
The drop resulted from reduced performance of both units, as shown on the following chart of capacity factors. The magnitude of the 2009 problems is clear when one considers that the

capacity factor for Unit 2 was more than 10 points lower than it had ever been in the last ten years, while Unit 3 was 15 points lower.



Other measures of performance in 2009 traced the same pattern, with large drops in availability and increases in heat rate. Discussions with management indicate an internal belief that this was simply a string of bad luck. While that may be true, such a result should be reached only when no other logical reason can be found. It would appear, however, that this is the initial conclusion reached by the cooperative, and there does not appear to be any analysis supporting such a conclusion.

The two factors (availability and the economics of dispatch) resulting in such low generation in 2009 may in fact be related. It appears that the units were run back regularly during 2009, and operated below full power. Consider the following chart which shows the capacity factor for the two units only when they were available. This only occurred once before in the last ten years, in 2002, and then to a lesser extent. It would appear that the units lost 15-20 percent of their output in 2009 due to less frequent dispatch.



The major reason for this phenomenon seems to be a loss of competitiveness due to AEPCO's new coal contract. As a direct result of its higher dispatch costs, the station is being displaced by other, less expensive generators. In addition to day-to-day dispatch decisions, AEPCO's agreement with the Salt River Project for a 100 MW contract purchase from Apache has lost its effect, presumably because SRP can obtain the energy more economically elsewhere. Importantly, at the present time, the competitiveness issue will be present going forward, and the SRP contract expires at the end of 2010. On the surface, then, unless some actions are developed to increase sales, the low capacity factors at Apache will be continuing, and perhaps worsening.

The second issue of importance in 2009 was the number of outages, which was well beyond what could have been reasonably expected. An analysis of outages will be presented in the next section. For now, however, the question to be asked is whether there is a relationship between the increased cycling to which the units were subjected and the increased number of outages. It will be noted that the units have run at an average 96.7 percent when available over the prior five years (2004-2008). It can be assumed that this meant little cycling of the units. It is not unreasonable to question the degree to which these 30+ year old units might suffer when subjected to this new mode of operation. This is simply one possible root cause for the recent outages that should be considered in AEPCO's analysis of station performance.

The key observation here is that there are forces at work that are impairing Apache's flagship assets. Further, the inability to run the units at near full capacity may be having a higher cost than simply the lost revenue. If so, this suggests that management can afford more forceful actions to increase output. One option suggested by Liberty is to seek a shared savings arrangement with the mines and railroad to lower the dispatch costs for what is now the lost generation. To the extent that dispatch costs are lowered, AEPCO will be able to purchase more coal to the benefit of its suppliers as well.

Although it might be too soon to tell if 2009 was simply an unusual year for ST2 and 3, the early experience in 2010 may provide some indication. The availability data is likely misleading, because the first five months of the year include months favored for planned outages. In fact, there was only one forced outage in the period. Any conclusions drawn from the availability data would support an improving trend.

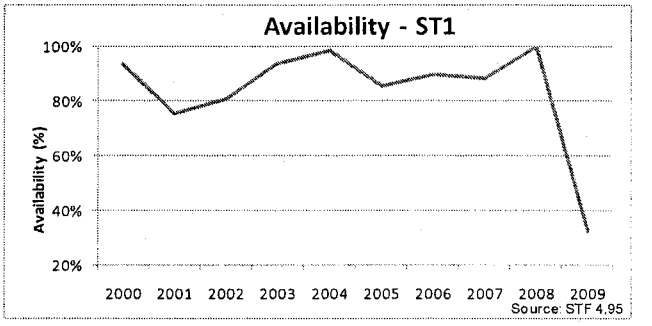
ST2 and 3 Performance				
	ST2		ST3	
	2009	2010 thru May	2009	2010 thru May
Availability	89.5	72.0	80.7	93.4
Capacity Factor	69.3	50.3	63.4	76.3
CF while available	77.4%	69.9%	78.6%	81.7%

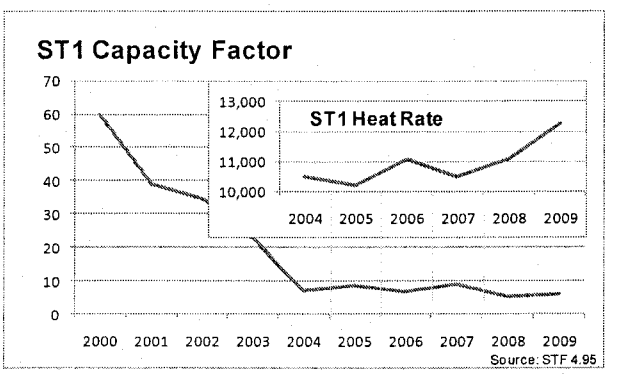
Source: STF 4.59 and 5.20

The capacity factor situation, or more precisely the dispatch issue, shows no improvement in 2010 and supports the notion that this is a long-term problem.

b. *Steam Unit 1 and Gas Turbine 1*

These units (referred to as "CC1") have operated in a combined cycle mode. Their role has changed considerably in recent years. CC1 operated at a 60 percent capacity factor in 2000, that rate declined to the mid-single digits by 2004, and has remained there since. On the surface, there arises a real question as to the viability of an old steam unit like ST1, particularly recognizing its substantial declines in reliability. ST1 experienced boiler-tube leaks in 2009, producing an availability factor of only 32 percent. ST1 has been down for re-tubing in 2010, thus producing an availability of essentially zero through May of this year. Meanwhile, ST1's overall efficiency has deteriorated sharply through the years. Management has attributed this to several factors:[44]





- The primary reason given is the decline in capacity factor.
- A second reason is the shift in 2004 to two-shift operation; *i.e.*, taking the unit off line at night and starting up in the morning.
- A lesser and temporary reason is the prolonged loss of a feedwater heater.

The accompanying chart shows the decline in capacity factor since 2000. The insert shows that heat rate has deteriorated considerably since 2004, when the capacity factor stabilized below 10 percent. This suggests that the capacity factor was not responsible for all, or perhaps any, of the loss of efficiency since 2004, which amounted to 17 percent.

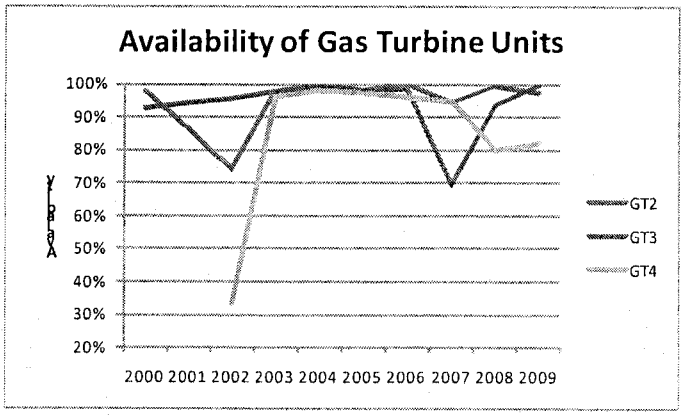
Factors such as these raise the question of the appropriateness of continued operation of and investment in CC1. Management has asked that question as well, commissioning a study completed April 5, 2010.[45] The study compared continued operation through 2020 versus placing the unit in "long term standby." This latter option considered two beginning dates for standby: 2011 and 2015. Major conclusions reached by that study include:

- "The continued use of CC1 for reserve and seasonal peaking capacity will still be, by a substantial margin, the most economic alternative of those evaluated for the members."
- Other than the serious boiler tube leak situation in 2009, "CC1 is in good condition. The steam turbine was overhauled in 2009 and the gas turbine in early 2010." With the boiler repairs underway in 2010, "CC1 is expected to operate on a seasonal basis for the remainder of this decade without further overhauls."

Other factors important in evaluating the future role of CC1 are the station's unique role and the nature of the AEPCO system. AEPCO has indicated that "the limited ability to import replacement power on the SWTC system" can lead to very high replacement costs and involuntary curtailments, should CC1 or similar capability not remain available. This limitation raises the value of the unit to AEPCO, although management did not explicitly address these factors in the study.

c. *Gas Turbines 2, 3, and 4*

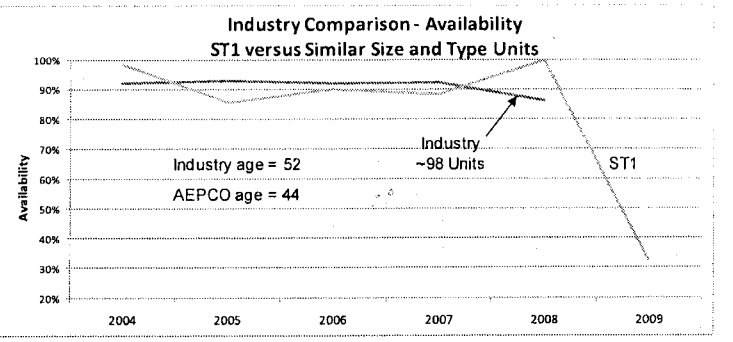
These three gas turbines function as peaking units. Availability of all of the units has generally been above 90 percent, with an occasional year that is much lower. Heat rates for all three units have varied widely through the years. Given the limited role of the units as capacity resources and their infrequent operation, performance deviations observed to date do not evidence significant problems, nor raise concerns like those applicable to the future of the steam units.

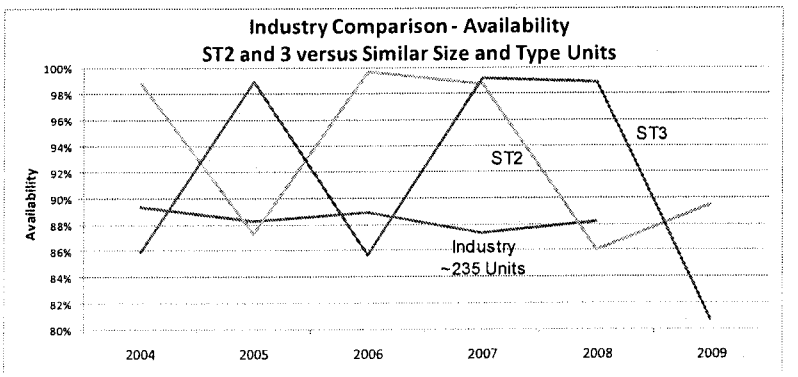


d. *Industry Comparisons*

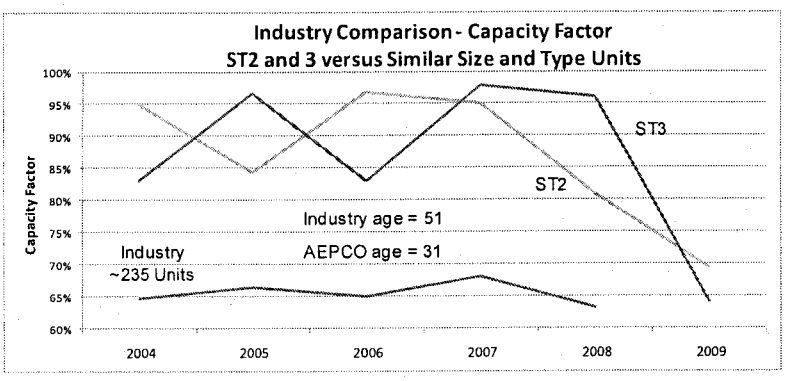
AEPCO's internal performance data indicates general deterioration; however, comparing AEPCO performance to industry data produces a different view. AEPCO units have generally performed well when compared with similar size and type units operated by others. This comparison does not negate the significance of the questions raised by AEPCO's problems in the past year or two; they continue to have real significance for the future of the station. An industry comparison does, however, show that these units have been relatively good performers for a fairly long historical perspective.

The adjacent chart illustrates ST1 availability versus similar units as reported in GADS.[46] ST1 availability was slightly below industry experience since 2004, until dropping precipitously in 2009. Note that the nearly 100 units in the data base are on average 8 years older than ST1. AEPCO therefore, has not compared well by this measure.





ST 2 and 3 compare much better to their industry counterparts, although they are substantially younger than the industry average. The industry plants' average age exceeds 50 years; therefore, they would not generally be expected to be playing a significant, high-performance role for their operators.



Despite the sharp drop in capacity factor last year, these two units are still generating at levels typical of the industry. Availability, on the other hand, is considerably higher at Apache. The units about equal the industry average during outage years, and far exceed them in non-outage years.

Making comparisons with others requires recognition that there exist differences in: (a) the roles assigned to the generating units, and hence their owners' expectations, and (b) the age of the units. AEPCO intends ST2 and 3 to operate as base load units. The data clearly indicates that such units are very frequently employed as intermediate units by others who operate similar units. The AEPCO economic data above suggests that ST2 and 3 may indeed be evolving to intermediate status. If so, its comparisons to industry data may look quite different in future years. Note also that the industry comparison units are 20 years older than Apache ST2 and ST3, which also affects any comparisons of data involving them.

The availability of AEPCO's gas turbines as compared with the industry shows mixed results. Unit 1 has had problems, but Unit 2 has consistently had availability in excess of 95 percent. Other than one particularly low year, GT3 availability has also been well above industry results.

Unit 4 has dropped to very low availabilities in the last two years. The engine on the latter unit was upgraded in 2009.

4. Outages

Unit outages, as the preceding data suggests, ran above normal in 2009. On a broader basis and over a longer term perspective, it does not appear that AEPCO has focused considerable, structured attention on the analysis of outage trends or their root causes. Liberty's data requests yielded a great deal of raw data but not analysis of what that data means, what trends exist, what patterns might suggest about operating or maintenance practices, or what interest may exist for delving further into outage causes.

On a more targeted basis, AEPCO has prepared technical analyses of some equipment problems. This work appears to be thoughtful and of high quality.[47] The recommendations from these analyses are limited and it is not clear what actions, if any, management has taken as a result of the study and thought put into this work. AEPCO also uses outside vendors and engineers to assist in consideration of equipment issues; this application of supplemental talent and experience is sound.

a. *Planned Outages*

The steam units have undergone five major, planned outages in the last few years. The accompanying table shows that all five of them ran over the planned duration (by an average of 9.6 days or 30 percent). This degree of overrun is problematic. Reported industry data suggests that outage extensions on these types of units is atypical.

Steam Units - Planned Major Outages				
Schedule Performance				
Unit	Year	Planned Duration (Days)	Actual Duration (Days)	Overage (%)
ST1	2006	18	35	94%
	2009	43	57	33%
ST2	2008	44	49	11%
ST3	2006	30	38	27%
	2009	27	31	15%
	Total	162	210	30%

AEPCO has not applied significant levels of formal and structured outage planning, but this does not mean that planning practices are nonexistent. To the contrary, it appears that a great deal of work goes into planning outages. AEPCO provided examples of such work to Liberty.[48] AEPCO points out that, in lieu of a "written outage plan," it conducts detailed roundtable discussions to address outage scope, budgeting issues, resource allocation, and other needed actions.[49] The need for structure and formality is somewhat a function of size and complexity. AEPCO clearly does not have the same needs as, for example, a large station with planned outages involving thousands of work activities and severe cost penalties for outage extensions. But it is also clear that Apache has challenges that suggest that the other end of the spectrum is not appropriate either.

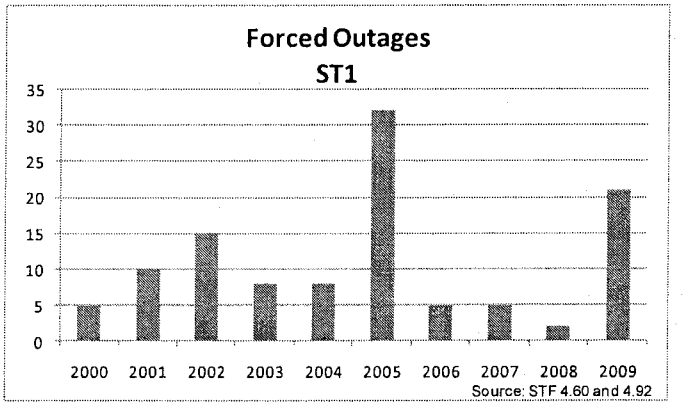
Steam Units - Planned Major Outages				
Cost Performance				
Unit	Year	Budget (Thousands)	Actual (Thousands)	Overage (%)
ST1	2006	275	221	-20%
	2009	2,500	3,511	40%
ST2	2008	7,091	7,995	13%
ST3	2006	5,312	5,653	6%
	2009	6,325	5,668	-10%
	Total	21,503	23,048	7%

Cost performance during planned major outages has also been a problem, although to a lesser extent than schedule. Some outages came in under

budget but, on a cumulative basis, there has been a 7 percent overrun. Apache includes a 10 percent contingency in the budget, which is not unusual or inappropriate. The plant does not include any contingency on schedule which, for straightforward work scope, is typical.

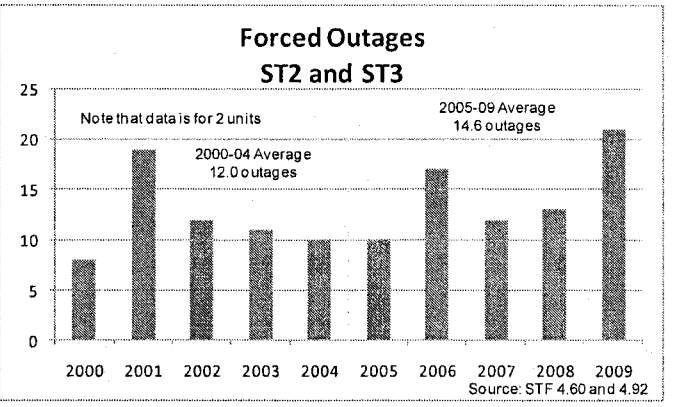
b. *Forced Outages and Reductions of Output*

AEPCO tracks the forced loss of generation in its data by: (a) forced outages, and (b) de-ratings, in which an event requires the plant to run at reduced output while addressing the event. Where de-rates are considered, AEPCO generally uses an equivalent outage duration, which corresponds to the fraction of capacity lost. For example, if the unit is forced to run at 50 percent of capacity for ten hours, the equivalent duration is 5 hours.

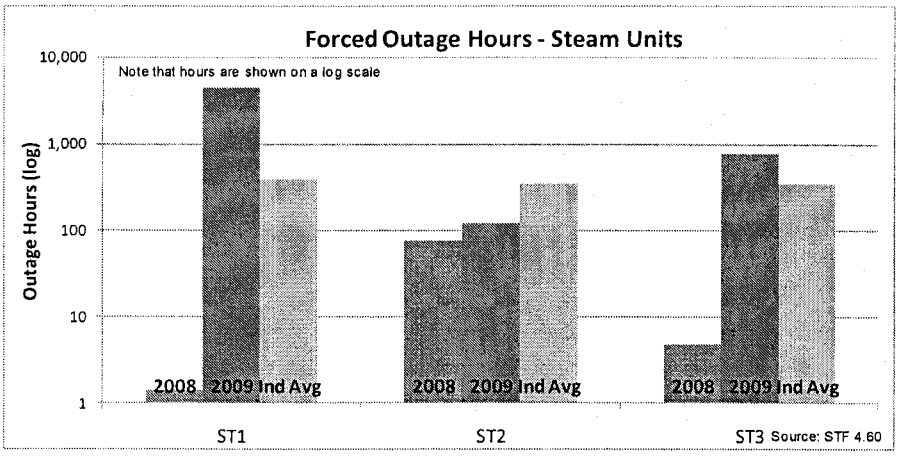


In evaluating reliability based on the number of forced outages per year, ST1 demonstrates weaker results than other similarly sized and type units have experienced. The accompanying chart shows sporadic results, ranging from 2 outages in 2008 to 31 in 2005. Typical industry performance for such units is about 2 forced outages per year. Moreover, Apache 1 is about 8 years younger than the average unit. ST1 forced outages thus run well above industry experience. The same remains true even after excluding the two very bad years (2005 and 2009) from the data.

Station management characterized these high rates as out of the ordinary, and there is a basis for such a characterization, especially for ST1. The accompanying chart for ST2 and 3 shows, however, that a "single aberrant year" does not tell the full story. The number of annual outages is growing with time. The average number of outages in the last years is 22 percent greater than the corresponding number for the prior five years. The average number of outages for similar size and type units is about 8 forced outages per unit, which would equate to 16 for the two units compared at Apache. Moreover, the peer units are about 20 years older than are ST2 and ST3. Notwithstanding the 2009 performance, it can be concluded that the Apache units are superior to their older peers but are trending towards industry levels as they age. It is this apparent trend, while the units are still young compared to their peers, that should give rise to sufficient concern to warrant management study.



Examining reliability as measured by total lost unit hours due to forced outages causes the Apache units to compare well with the industry for 2008, but not as well in 2009 (note the scale on the accompanying chart is logarithmic). ST1 was off for more than half the year. With the exception of ST3 in 2009, the coal units performed better than the industry average, which should be expected given that the average industry age is 20 years greater for these units.



Lost generation due to maintenance and operating issues, excluding that cause by unit outages, are characterized as de-ratings. Such events can be relatively frequent at Apache. The bottom line effect in terms of lost generation, however, has generally been small, both on an absolute basis and on a basis relative to the industry. The accompanying table shows the annual average number of de-ratings and the associated lost hours. The large number of hours on ST1 is due almost entirely to a single circulating water pump issue in 2008 that resulted in an extended de-rating of about 15 percent.

Average Annual Derates (2008-09)

	Events	Equiv Hours
ST1	7	268
ST2	42	53
ST3	22	55

c. *Outage Causes*

Liberty conducted a detailed analysis of outage causes for the three steam units in 2008 and 2009. In addition, Liberty examined the outage data back to 2000 in a search for broad trends. For these analyses, we summarized the large number of outage codes into 17 summary codes that are a simpler and more effective characterization of unit issues. The results of the 2008-2009 analysis are shown in the next table. The major causes of outages in this two year period are typical:

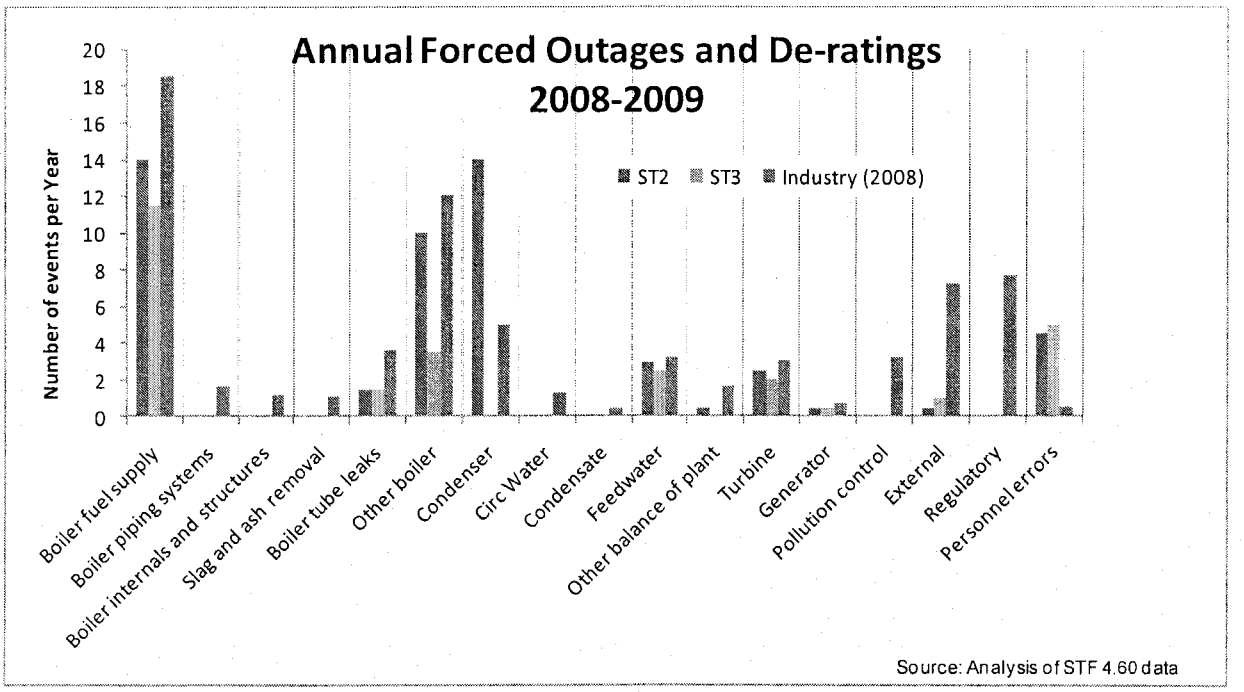
- Boiler tube leaks, especially on ST1
- Fuel supply (a broken gas regulator on ST1 and multiple mill-related de-rates on the coal units)
- Turbine and generator issues
- Condenser de-rates on ST2 due to tube leaks.

The two-year analysis provides little in the way of insightful conclusions. There are the obvious concerns with so many boiler tube leaks on ST1. Management has addressed that issue. Boiler tube leaks and mill problems present continuing issues on the coal units, but they remain in line with industry expectations. The same applies to turbine and generator problems. The ST2 condenser leaks merit further analysis, as performance has been well below the industry and seems to be worsening, at least over the limited two-year period.

Outages and De-rates by Cause (2008-09)								
	Unit 1		Unit 2		Unit 3		Total by Cause	
	Number	Equiv Hours	Number	Equiv Hours	Number	Equiv Hours	Number	Equiv Hours
Boiler fuel supply	3	1240.95	28	87.13	23	25.70	54	1,353.78
Boiler piping systems								
Boiler internals and structures								
Slag and ash removal								
Boiler tube leaks	10	2053.87	3	106.42	3	109.45	16	2,269.74
Other boiler	7	84.65	20	39.48	7	5.45	34	129.58
Condenser			28	52.07			28	52.07
Circ Water	3	420.53					3	420.53
Condensate								
Feedwater			6	5.71	5	54.04	11	59.75
Other balance of plant	4	4.46	1	0.37			5	4.83
Turbine	3	778.9	5	6.71	4	255.43	12	1,041.04
Generator	3	202.49	1	2.67	1	424.53	5	629.69
Pollution control	1	0.12					1	0.12
External			1	0.07	2	0.24	3	0.31
Regulatory								
Personnel errors	3	174.61	9	5.07	10	3.45	22	183.13
	37	4,960.58	102	305.70	55	878.29	194	6,144.57

Source: Analysis of STF 4.60 data

The following chart, which compares Units 2 and 3 against industry data, confirms the conclusion that not much out of the ordinary can be observed. Apart from the ST2 condenser issues, however, personnel errors stand out as a major deviation. This category, at the far right of the following chart, includes unit trips caused by operators, maintenance personnel, or contractors. Apache error rates fall well above industry expectations.



Liberty examined outage data back to 2000, in an effort to determine the nature and consistency of personnel errors leading to unit trips. The following table provides the history.

Unit Trips Attributed to Personnel Errors

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total	Industry
ST1	2	3	4	1	1	9	0	0	0	2	22	0.5
ST2	1	1	1	3	2	1	1	3	1	3	17	3.5
ST3	1	2	0	2	3	1	0	3	3	3	18	3.5
Total	4	6	5	6	6	11	1	6	4	8	57	7.5

Source: STF 4.60 and 4.92. Industry data are from GADS 2004-2008 – value shown is 10 times the annual average.

The data suggests recent improvement in ST1, which might at least partly be due to the fact that the unit does not run very often (especially since 2004). The coal units, however, do not demonstrate an improving trend. Their pattern over a ten year period shows a frequency of unit trips of ST2 and ST3 from personnel errors that is five times the industry average.

It does not appear that structured analyses or corrective measures have been applied to address this specific issue. Management has, however, taken numerous steps to deal with the question of outages in general, including:[50]

- An outage analysis team meets after each unit trip to seek causes and corrective measures.
- Discussions on outage trips are held with operators and maintenance personnel in their respective pre-shift tailgate meetings.
- Managers, foremen, engineers and other key staff address outage causes in their morning staff meetings.
- There is ongoing personnel training, including a new General Physics web-based program.
- There is an ongoing process of revising procedures to incorporate lessons learned.

These measures are all positive; however, it appears that they have not been effective (at least to date) in mitigating unit trips attributed to personnel errors. The magnitude of this issue, and its impact on plant performance and economic effectiveness, indicates the need for added management attention, analysis, and corrective action.

d. Replacement Costs

Having discussed above the higher number of outages for the steam units in recent years, it becomes appropriate to consider the cost to AEPCO of those outages. AEPCO responses to data requests[51] estimated replacement power costs by pricing the power at the average for the month of each outage. Similarly, AEPCO priced the avoided fuel costs at its fuel costs for the subject month.

Added Power Costs from 2008-2009 Outages

	All Outages > 2 days			Forced Outages > 2 days		
	Outages	Days	Penalty ($1,000)	Outages	Days	Penalty ($1,000)
ST1	7	71.4	-57	7	71.4	-57
ST2	6	81.3	8,626	3	8.2	703
ST3	9	53.1	2,946	3	11.9	493
Total	22	205.8	11,515	13	91.5	1,139

Penalty = Replacement cost less fuel cost
Source: STF 4.63 and 10.13

Liberty has summarized the results for all outages in 2008-2009 that lasted two days or more. For the three steam units there

were 22 such outages with total replacement costs less fuel costs of [redacted] million. However, when limiting the sample to forced outages only (totaling 13 in number), as Liberty believes is more appropriate for such an analysis, the amount drops markedly to [redacted] million.

A single ST2 planned outage starting in March 2008 accounts for 65 percent of the replacement costs less fuel costs. The reported replacement costs for that period were an uncharacteristically high $69/MWh.

5. Maintenance

In examining the maintenance program at Apache, Liberty sought to answer the following basic questions:

- Is an effective maintenance philosophy and strategy in place?
- Are Apache's maintenance practices managed effectively?
- Does the maintenance program adequately balance cost and reliability?

One should expect a well managed maintenance program to be clearly defined and documented in terms of its objectives, priorities, and the strategies that support them. Such formalities are essential in large, complex organizations, but less important in smaller operations, where personnel tend to be tied together more closely and knowledge of the power plant is very high among the team. The latter characterization surely applies to the Apache Station, allowing its management and staff to be effective with a significantly lesser degree of formality.

Liberty believes that an effective maintenance philosophy and strategy is indeed in place at Apache, but there is little documentation to support it. Interviews, consideration of the SAP maintenance management system, responses to relevant data requests, and observations at the plant all support this conclusion. Clearly articulated policies and strategies have a real benefit regardless of unit size. Nevertheless, Liberty found in Apache's programs no gaps that have a material effect on performance.

a. Maintenance Programs and Systems

The following description offers key characteristics associated with the Apache maintenance systems, as described by management:[52]

> *"A computer maintenance management software program (SAP) is used to schedule and monitor the entire maintenance process. Preventative equipment maintenance work orders all have detailed instructions that outline the various steps that a craft person needs to perform in order to complete the required work. This part of the program is continually monitored for such things as instruction accuracy, parts and tool requirements and schedule frequency." "Apache has three full time maintenance planners on staff, and it is their responsibility to monitor the maintenance program and plan and schedule all necessary work throughout the year."*

The SAP system offers a sound tool that supports the station in multiple ways. The areas benefitted include the overall maintenance management system including work orders, materials

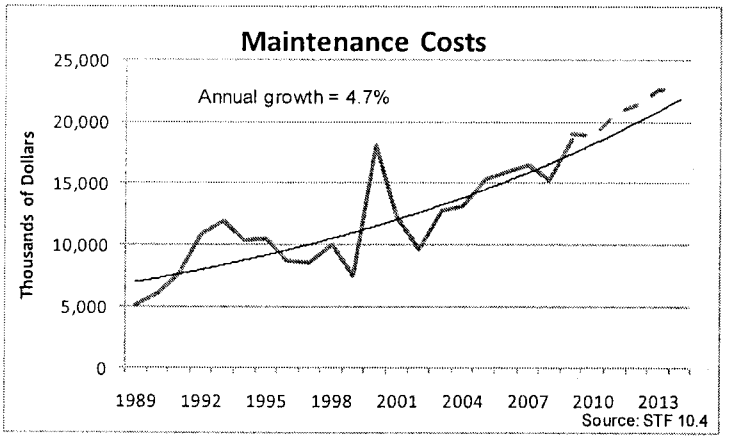
management, equipment histories and cost data. Liberty examined numerous sample reports submitted in response to data requests,[53] finding them all detailed and extensive. Liberty did not see any reports from the system that might be useful for management overview or overall performance monitoring. For example, there is no report on trends in maintenance backlog. One might reasonably conclude that the systems have value for getting the detailed work done and adequately support the planners and the workforce, but it is not clear they are being used to allow an appropriate perspective for management.

The scope of the management challenge is clear considering that there were 12,110 work orders created by the system in 2009. It is not clear, however, how that large effort is brought together for management reporting and analysis and how such reporting and analysis fits into the management process.

Apache also utilizes a Reliability Centered Maintenance program applicable to all rotating equipment. Staff reports that the program has been highly effective and cost beneficial, currently catching 90 percent of failures.

Management also reports that Apache enjoys a favorable balance between preventative and corrective maintenance, with 67 percent of work orders in the former category.[54]

b. Costs



There is nothing particularly revealing about total station maintenance costs. The spike (albeit small in an historical context) in 2009 would be expected, given the large number of outages and de-ratings. The growth going forward is not out of line with past growth, particularly because one might expect maintenance costs to grow faster with station age.

The root causes of the 2009 deterioration should be sought, and one obvious question goes to the adequacy of prior maintenance levels. Although that remains an appropriate question, nothing Liberty saw during the evaluation would lead to such a conclusion. Spending immediately before the 2000 spike seems to have been somewhat depressed for five or six, but if that contributed to future problems, they were more likely in that 2000 spike than in 2009. Liberty therefore has no basis to assume prior maintenance activities contributed to the 2009 performance issues.

6. Capital Additions

With age, investment needs grow, raising for all utility operators the inevitable question of "throwing good money after bad." With recent production trends at Apache, including a 40 percent decline in output since 2000, this question must be front and center. Liberty has examined this issue as it relates to this rate filing and the new plant placed in service. We can conclude that AEPCO's investments have been justified and appropriate. At the same time, it is

critical to define the station's future mission as it will likely become increasingly difficult to judge the cost-effectiveness of station improvements.

a. *Recent Investments*

Liberty reviewed the major capital projects (estimated at >$500,000 each) that were placed in service since 2006. This sample includes 18 projects with an eventual installed cost of $27.1 million. A review of the data provides some key insights:

- Many of the projects involved environmental issues, in response to specific requirements or modifications or improvements to pollution-related equipment.
- There were no qualifying projects associated with ST1. The single large project involved steam turbine blade replacement in 2009, which amounted to $268,000. A large project is planned to re-tube the ST1 boiler in 2010.
- There was only one qualifying project associated with the gas turbines – engine upgrade for GT4 in 2009.

Projects >$500K - 2006-2009
(Thousands of Dollars)

Unit	Project	Estimate STF 10.1	Actual STF 4.61
ST2/3	Cooling tower upgrades	12,182	9,477
ST2	NOx reduction	3,236	2,894
GT4	Engine upgrade	2,324	2,516
ST3	Gas recirc fan replacement	2,135	2,047
ST3	Boiler cleaning upgrades	2,100	1,451
ST3	Stack liner coating	1,190	1,002
ST2	Stack liner coating	1,431	996
ST3	Stack liner coating (2009)	930	985
ST2/3	Ash line piping replacement	908	960
Station	New deep well 70	1,260	948
ST2/3	Coal handling upgrades	1,134	906
ST2/3	Mercury CEM	598	689
ST3	Bottom ash hopper reline	579	587
ST3	LP FW heater upgrade	600	444
ST2	Upper loop spray nozzle	522	357
ST3	Scrubber tower upgrade	535	351
Station	Deep well line replacement	707	258
ST2	Scrubber tower upgrade	525	242
	Totals	**32,896**	**27,110**

Source: STF 4.61 and 10.1

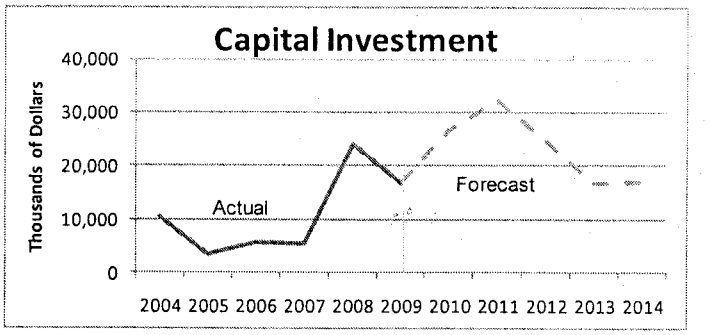
The listing of projects is typical for coal-fired units of this age. Liberty reviewed the justification for each of the listed projects as documented on the "Capital Project Analysis" sheets, and found all to be reasonable.

The content of the justifications is minimal compared to others Liberty has seen, including those prepared by SWTC for transmission projects. Some practices that might be questioned include limited presentation of reasonable options and the use of seemingly high replacement cost differentials in payback analyses.[55] On the positive side, the analyses are presented well, with all relevant information contained at a reasonable summary level and in an easy-to-understand construction. Liberty found that the analysis sheets provide ample information for the initial consideration of management and the board. Further, Liberty has no basis to question the diligence exercised by management or the board in questioning and testing the projects and their justifications.

In summary, Liberty finds that the major additions to rate base appear to be appropriate and justified on operational, economic, environmental and safety grounds.

b. *Future Investments*

Liberty has cautioned that the challenge associated with large investments in the future will be much greater as the role of the station changes, and AEPCO is likely to find justifications for major investments increasingly difficult. This issue is likely to surface sooner, rather than later, as suggested by the capital investment forecast for the next several years.



Source: STF 4.100

Note that actual and planned annual spending beginning in 2008 is more than double the levels of 2004-2007. However, Apache may not operate as the same type of station in the years ahead, compared to the characteristics of 2004. It would appear that, at least, the station will produce far less electricity and be somewhat less reliable. The appropriateness of a much higher and sustained level of capital spending is therefore a fair question, and one that management needs to consider seriously in the months ahead.

7. Facility Review

Liberty visited the Apache Station, and observed the steam units, the coal yard, and the warehouse and shops. The two coal units were in operation and ST1 was down for modifications. At the time of the visit, a coal train was being unloaded.

This review found the plant to be professionally staffed, with all of the personnel we met hospitable and helpful. The individuals supporting the site visit were expert in all facets of the plant and were able to fully answer all of our questions.

The facilities were generally clean by power plant standards and there was no real clutter throughout the plant. There appeared to be adequate provisions for maintenance activities, particularly including large, maintenance-friendly turbine floors.

The coal yard activities seemed efficient and the train unloading we witnessed proceeded with dispatch.

The supporting facilities, including the warehouse, weld shop and machine shop, seemed in excellent order. The machine shop is especially well outfitted in apparent response to the difficulty in finding local shops to provide timely support services. The warehouse operations are facilitated by SAP and the warehouse staff seemed comfortable with its use. Warehouse security seemed appropriate.

We visited the control room for ST2 and 3 and found it professionally staffed and orderly. Access to the plant is controlled by contract security, which appeared to be professional and capable.

In summary, our visit to the Apache Station yielded only positive comments about the facilities and staff at the station.

C. Conclusions

1. Technical performance, personnel and facilities are generally sound.

The management team was knowledgeable, engaged, open, and supportive of Liberty's evaluation. The organization appeared to have expertise and tools commensurate with the needs and challenges that AEPCO faces. With respect to factors relevant to this rate filing, Liberty's engineering analysis concludes that: (a) AEPCO's power plant operations are generally appropriate and typical of the industry, (b) AEPCO's investment in new and upgraded facilities has been appropriate for the demands placed on the cooperative, and (c) maintenance practices and spending appear to be consistent with the station's needs and good utility practice.

2. **Performance is generally sound from a technical perspective; while Liberty found no reason to call into question costs claimed in the current filing, AEPCO faces significant questions about the future of its units.** *(Recommendation #1)*

Liberty's review, as addressed in more detail in the following conclusions, found no major gaps in AEPCO performance. Liberty cautions, however, that a number of emerging issues may have a major impact on the station and its ability to serve the members in the future. A primary concern is the future role of steam units 2 and 3, the coal-fired units that currently produce more than 95 percent of the station's output. Operated in a base-load mode for about 30 years, these units now appear more likely to cycle, which would cause them to serve more as intermediate units. This change has resulted from a decline in the units' competitiveness due to a new coal contract, which in turn has reduced their dispatch, and contributed to the decline of the 100 MW sale to the Salt River Project. There is also a possibility that this new cycling of the units is having an impact on equipment, contributing to a significant drop in availability in 2009.

The dual effect of lower availability and less running time when available raises questions about the future role and economics of the station, as well as questions about the nature of future power supply for members. The answers to these questions will have a direct impact on decision-making at Apache and in power procurement. AEPCO should view the performance trends at Apache with significant concern. Major issues that do not appear to be the object of focused inquiry include:

- The continuing long term trend in declining station output which, if it continues, suggests a limited future for these units.
- The decline in reliability of the flagship units, ST2 and 3, which calls for an as-yet to be completed analysis of root cause. Maintenance and the effects of increased cycling of the units are two potential areas for study. It may well be that recent performance has simply resulted from a run of bad luck, but the data indicate that such a conclusion should not be accepted before suitable analysis.
- The increase in dispatch costs, as a result of the new coal contract, has resulted in ST2 and 3 being utilized much less than desired. It would appear that the units have become uneconomical as base load units.

It is not clear that these issues are getting the attention they deserve; they bear directly on the continuing viability of the station as an asset. Hostile forces are at work, and are well evidenced in the trend of performance. The key question at this time is whether 2009 conditions are anomalous or a warning of deterioration. There are real signs of the latter, as the issues facing ST2 and ST3 do not appear to be temporary.

3. Experience and recent management study confirm the continuing usefulness of CC1 and the gas turbine units.

Steam unit 1, a gas-fired boiler that operates in combined cycle with gas turbine 1, is a capacity resource. Its performance was also poor in 2009 and it has been out of service for the first part of 2010 for re-tubing of the boiler. AEPCO recently completed an analysis that justified further investment in ST1 (the boiler re-tube). This assumed that the recent improvements of the unit, including overhaul of both the steam and gas turbines, will likely assure reliable operation for at least the rest of the decade. Liberty does not have any reason to challenge this conclusion; however, it should be clear that this old unit brings risk with it. Prolonged outages, such as those experienced in 2009, could have a serious impact in the future. Note that AEPCO warns of potential involuntary curtailments in the years ahead due to limited import capability if this capacity is unavailable.

Management's April 5, 2010 study examined future options, concluding that continued use of CC1 for reserve and seasonal peaking capacity remained AEPCO's most economic alternative. The study's conclusions may seem surprising based on recent unit performance, but appear more credible from a longer-term perspective. Availability has been reasonable (although not up to average industry performance) for such units. If AEPCO can succeed in: (a) stabilizing availability at high levels going forward, and (b) holding maintenance costs at reasonable levels, it would appear that continued operation of the unit makes sense.

The three gas turbines have had good availability over time. AEPCO uses them as peaking units; any actual resulting deviations in performance give no reason to conclude that operating problems have arisen or that they will remain useful to AEPCO.

4. Apache has not suffered atypical losses of generation due to deratings.

Despite fairly frequent events that cause deratings, Apache has had only small levels of lost generation, both in absolute terms and by comparison with industry experience.

5. Maintenance has generally been effective, but a lack of formality and structure exists. *(Recommendation #2)*

Liberty's review of maintenance policies and practices found no reason to believe these activities are lacking. AEPCO employs good practices in preparing for and managing outages. The detailed systems used to plan, monitor, and execute work orders seem to be effective. On the other hand, summary level information, as might be expected for management to provide program oversight, does not appear to provide the perspectives that managers would usually require.

Consistent overruns in outage durations that AEPCO has experienced are not typical. AEPCO does not apply significant levels of formal and structured outage planning, nor does it need to, given the size of its fleet. However, results indicate a need for examining the creation of a somewhat more formal and structured approach.

Spending on maintenance has generally been consistent for many years, with occasional spikes, as might be expected. The only suggestion of potential under-spending might have been in the

late 1990s, but this is far from conclusive. Further, there is no reason to believe that today's reliability issues are arising from maintenance activities so long ago.

6. Apache suffers a particularly high number of trips due to personnel errors. *(Recommendation #3)*

The number of coal unit trips due to personnel errors at Apache has consistently been about five times greater than is the case for similar units. Performance at ST1 has been even weaker. Actions taken by management on this specific problem have been limited and not effective. This problem deserves greater analysis and more aggressive action by management.

7. Forced outages have not imposed significant cost penalties on AEPCO.

The 13 forced outages of 2008 and 2009 combined have caused AEPCO to experience total replacement costs less fuel costs of [redacted] million. Fuel and purchased power expenses in these two years are in the range of $140 million. Thus, the penalty suffered by AEPCO due to the numerous outages in this period was moderate.

8. Past capital additions have been appropriately planned and executed.

AEPCO's recent investments in plant have been justified and appropriate. The review underlying this conclusion included all of the capital project justifications for large projects. Liberty found them to be in order and supportive of management's decision-making needs. Liberty found the listing of projects typical for coal-fired units of this age. Liberty reviewed the justification for each of the listed projects as documented on the "Capital Project Analysis" sheets, and found all to be reasonable.

The content of the justifications is minimal and Liberty found limited presentation of options and the use of high replacement cost differentials in payback analyses. Improvement in these areas could prove beneficial. However, Liberty found the analyses to be well-presented, in appropriately summarized and understandable format. The analysis sheets provide management and the board with sufficient information. Liberty found no reasons to question the diligence exercised by management or the board in questioning and testing projects.

In summary, past spending appears to have been appropriate; however, questions should be raised concerning future spending. Actual and forecasted spending from 2008 to 2014 is more than double the annual levels between 2004 and 2007. Considering the uncertainties on the future role of the station as discussed above, the appropriateness of a much higher and sustained level of capital investment in the future is not clear.

9. Liberty's on-site examination of Apache found station conditions to be appropriate.

Plant staff demonstrated sufficient breadth of expertise and was knowledgeable of the details of station conditions. The plant was in a clean and secure condition and exhibited sufficient provision for the conduct of maintenance activities. The train unloading Liberty witnessed proceeded without incident. Support facilities were well equipped. The control room was well staffed and orderly.

D. Recommendations

1. Conduct a study of the future role of Apache and how that role relates to member needs for future power supply. *(Conclusion #2)*

It does not appear that AEPCO has yet conducted the type of analysis needed to fully get on top of what seems to be a serious issue with the Steam Units 2 and 3. That analysis should be undertaken on an urgent basis and corrective actions, to the extent practical, implemented. The results of the recommended study should provide guidance for future decision-making, such as power procurement strategies and the appropriateness of future investments at the station. The causes and permanence of recent Apache performance can be debated; however, there is reason for management to take a hard look at the future role of the Apache assets. The historical role of the two key units as base load generation may be coming to an end.

AEPCO management has been aware of performance results and it has expressed concerns about their significance. What Liberty did not observe, however, was the performance of significant analysis to answer questions, such as:

- Why so many problems suddenly appearing in the same year
- Are there common root causes
- Are these isolated random events or an indicator of long-term decline?

Management should commence very soon an analysis of the future of the station and how any changes might influence continuing decision-making. Station output is down 40 percent since 2000, and continuing declines appear likely; therefore, there is an immediate need to answer these important questions.

Management should investigate options for improving the economics of ST2 and ST3 in order to improve capacity factor and station efficiency. Shared savings arrangements for incremental load with coal and transportation vendors are examples of the initiatives that AEPCO should consider.

2. Examine methods to create more structured and formal outage planning and management. *(Conclusion #5)*

Liberty agrees that sophisticated outage management systems and extensive pre-planning, which are easily justified in large utilities, will not necessarily be cost-effective at Apache. On the other hand, an approach with more structure and formality, tailored to Apache's size and needs, merits focused examination by AEPCO.

A helpful start in this regard may be a summary level "outage plan," prepared several weeks in advance of all planned outages. Basic outage parameters would be addressed, including major tasks, priorities, budgets, schedules, critical paths, resource requirements, shift and overtime plans, risk factors and risk mitigation strategies. The intent is to provide assurance that all such factors have been considered on a thoughtful basis and that management's expectations for the outage are clear.

3. Examine the root causes of trips resulting from personnel errors. *(Conclusion #6)*

Management should undertake a study to determine the root cause of personnel errors and to define actions to significantly reduce steam unit trips from this cause.

IX. FPPAC

A. Background

AEPCO has had a Purchased Power Fuel Adjustor Clause ("FPPAC") since 2005. AEPCO's filing in its current rate proceedings anticipated, but did not include a revised FPPAC and a Plan of Administration to support its execution. On May28, 2010, AEPCO filed in response to a data request drafts of a number of documents related to its proposed new FFPAC:

- Six-page Plan for Administration
- Five-page tariff schedule for PRMs
- Five-page tariff schedule for ARMs.

Liberty reviewed the continuing need for an FPPAC and the specific proposal that AEPCO has offered to amend it.

B. Findings

1. FPPAC Introduction

Decision No. 68071 (April 14, 2005) in Docket Nos. E-01773A-04-0528 and E-04110A-04-0527 addressed AEPCO's prior application for a general rate increase. Decision No. 68071 introduced AEPCO's FPPAC to track and to provide for the collection of the difference between: (a) actual fuel, purchased power, and wheeling costs, and (b) those established as base costs by the Decision No. 68071. The Decision set these base costs at 1.687 cents/kWh for ARMs and at 1.603 cents/kWh for PRMs. Demand charges associated with a certain power purchase agreement was the factor that differentiated these two base costs.

Decision No. 68071 attached a number of conditions to the approval of the FPPAC:

- Expiration in five years unless extended by the Commission
- Fuel and purchased power costs subject to prudence review at any time
- FPPAC calculations subject to review at any time
- Refund of FPPAC collections determined to be imprudent
- Filing of monthly reports with Staff detailing FPPAC calculations addressing the items proposed by Staff
- Monthly reports regarding fuel and power purchases and plant operations, containing the information proposed by Staff.

Decision No. 68071's approval of the FPPAC noted that fuel and purchased power comprised almost one-half of AEPCO's test year (2003) costs, and acknowledged AEPCO's assertion that volatility in such costs comprised a primary reason for the margin loss the cooperative suffered in 2003.

2. Current FPPAC Calculation

The adjustor rate was initially set at zero and was to remain at that level until October 1, 2006. At that date, and at each subsequent six-month interval, the adjustor would automatically change

as required to recover the difference between actual and base costs. Decision No. 68594 (March 23, 2006) accelerated the first (October 1, 2006) reset date to April 1, 2006.

AEPCO must file one month before each October and April reset date a calculation of the new, proposed charge with a revised ARM tariff and PRM schedule. The calculation of the new charge consists of two parts, computed separately for ARM and PRM customers:

- A Power Cost component derived by: (a) adding the fuel, purchased power, and wheeling costs for the most recent 12 months, and (b) dividing this sum by kWh energy sales during the same 12 months
- A Bank Account component derived by: (a) calculating the total over or under recovered fuel, purchased power, and wheeling costs since clause inception, and (b) dividing this amount by the same kWh amount used to derive the Power Cost component.

The charge contained in the AEPCO filing becomes effective unless suspended by the Commission. Because the Decision established two different base costs (one for ARMs and another for PRMs), each ARM pays one adjustor rate, while each PRM pays a different adjustor rate.

3. 2008 FPPAC Review

Decision No. 70354 (May 16, 2008) addressed AEPCO's February 27, 2007 and February 29, 2008 requests to review (as contemplated in Decision No. 68071) the efficacy of the FPPAC. AEPCO pointed out that escalating fuel and purchased power costs were producing a bank balance that, after accounting for seasonal ebbs and flows, was growing too fast to recover past undercollected balances using the 12-month total kWh divisor in the FPPAC.

Decision No. 70354 noted that significant fuel and purchased power costs had caused the amount by which AEPCO had undercollected (the second, or "Bank Account" component of the FPPAC) to grow to $11.8 million by September 2007. It was undercollected by $4.9 million in January 2008 (the last month for which the Decision reported a balance). AEPCO proposed to alter this component by reducing the divisor from the most recent 12 months to the most recent 6 months of kWh energy sales. This change would have the practical effect of doubling the rate of recovery of an undercollected Bank Account balance.

The Commission observed (Decision No. 70354, paragraph 25) that, "AEPCO's proposed change to accelerate recovery will not change the inherent lagging tendency of the methodology. A completely different methodology may be needed to accomplish that, but that type of change is not an issue for the instant proceeding." Nevertheless, the Commission did determine that the change represented an appropriate interim means for accelerating recovery and thereby lessening the financial burden that even the reduced balance of $4.9 million was imposing on the Cooperative and its customers. The balance remained at about $4.4 million for ARM and PRM members combined, as reflected in AEPCO's calculation as of December 31, 2009 for use in resetting the adjustor rate on April 1, 2010. Natural gas prices have remained low, allowing the balance to drop. It has in recent months fallen into the $2 - $3 million range.[56]

Decision No. 70354 also discussed concerns by the PRMs about the failure of FFPAC calculations to consider differences in costs of energy supplied to them and to ARMs.

Specifically, one PRM observed that, although PRMs take primarily lower cost power from coal units, AEPCO was allocating to them higher natural gas fuel costs more associated with sales to ARMs. Staff believed that these issues could best be addressed in the next AEPCO rate filing (the one at issue in these proceedings). In this case, AEPCO and its ARM and PRM members have agreed to changes in the allocations of costs to differentiate energy costs associated with base resources and other resources.

4. Costs Included in the FPPAC

The costs that have been included in the FPPAC since inception include the cost of fuel and natural gas consumed in AEPCO generating stations, as recorded in RUS Accounts 501 and 547. The descriptions of these accounts follow:

501 Fuel.

A. *This account shall include the cost of fuel used in the production of steam for the generation of electricity, including expenses in unloading fuel from the shipping media and handling thereof up to the point where the fuel enters the first boiler plant bunker, hopper, bucket, tank, or holder of the boiler-house structure. Records shall be maintained to show the quantity, B.t.u. content and cost of each type of fuel used.*

B. *The cost of fuel shall be charged initially to Account 151, Fuel Stock, and cleared to this account on the basis of the fuel used. Fuel handling expenses may be charged to this account as incurred or charged initially to Account 152, Fuel Stock Expenses Undistributed. In the latter event, they shall be cleared to this account on the basis of the fuel used. Respective amounts of fuel stock and fuel stock expenses shall be readily available.*

547 Fuel.

This account shall include the cost delivered at the station (See Account 151, Fuel Stock) of all fuel, such as gas, oil, kerosene, and gasoline used in other power generation.

A different RUS Account (158) addresses the costs of SO_2 allowances. Therefore, AEPCO's FFPAC, in contrast to many others, recovers no costs of SO_2 allowance purchases or sales. AEPCO has generated sufficient numbers of allowances to avoid the need for purchases. AEPCO has made a moderate number of sales in the past. It has in recent years been banking them, however, given a desire to assure a reserve sufficient to support operations and low market prices for allowances. RUS considers these allowances to be security for its loans; therefore, RUS requires that the proceeds of sales of allowances be applied to loan balances.[57]

AEPCO's FFPAC also includes the costs recorded in RUS Account 555 (Purchased Power). The description of this account follows:

555 Purchased Power.

A. *This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall also include, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, and spinning reserve capacity. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, or capacity. Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.*

The AEPCO FPPAC describes purchased power as including energy purchased on an economic dispatch basis, purchases made as a result of scheduled outages, and "all such" kinds of purchases made to substitute for AEPCO's own, higher cost energy. Another tariff clause includes purchases other than these, if recorded in RUS Account 555. Liberty asked about the intent of the language in these tariff provisions (lettered paragraphs B. and C. under the Power Cost Adjustor Rate section of the tariffs for ARMs and PRMs) because it seemed to imply that purchases for certain reasons (*e.g.*, as a result of forced, rather than scheduled outages) would not be recovered through the FPPAC. AEPCO advised that the language did not intend any exclusions, but rather to make clear that all forms of power purchases are included. The FPPAC tariff language does, however, exclude the demand and energy costs associated with sales for resale (presently including the City of Mesa and SRP).

The last cost element included in the FFPAC is wheeling (RUS Account 565). AEPCO excludes, however, the costs it pays to SWTC for network transmission service for the ARMs, because those costs are passed directly through to the ARMs.

5. FPPAC Change Proposed by AEPCO in Current Rate Proceedings

The new FPPAC that AEPCO proposes would continue to include the same categories of costs and it would continue to treat ARMs and PRMs differently. Its principal change would be to separate the FPPAC into Base Resource and Other Resources categories. Separate adjustor rates would be created for each of these two resource types. The definitions of the two resources categories are:

1. Base Resources:
    a. AEPCO Steam Turbine Units 2 and 3
    b. Economy purchases displacing these units
    c. Western Area Power Administration contract purchases by AEPCO
    d. Wheeling expenses associated with delivery of these resources
2. Other Resources:
    a. AEPCO Steam Turbine Unit 1 (including Gas Turbine 1) , Gas Turbines 2, 3 and 4.
    b. Contract purchases that serve the combined scheduled loads of Class A members (i.e., ARMs and PRMs)
    c. Other power purchased (except for those included above in item 1.b.)
    d. Power acquired by purchase or through resources to which a member has expressly agreed to participate

Each ARM and PRM would be charged (or credited as appropriate) for the kWh that it has received from each of the two resource types. Thus, for example, a PRM that secures its non-base requirements from the market, thus taking from AEPCO only its share of base resources, would be responsible for no energy costs associated with Other Resources.

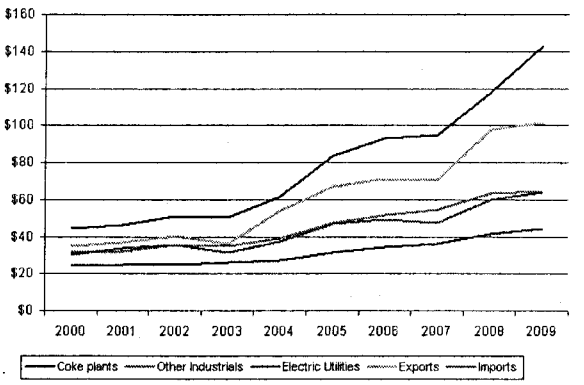
For both ARMs and PRMs, the new FPPAC would follow a similar calculation process:

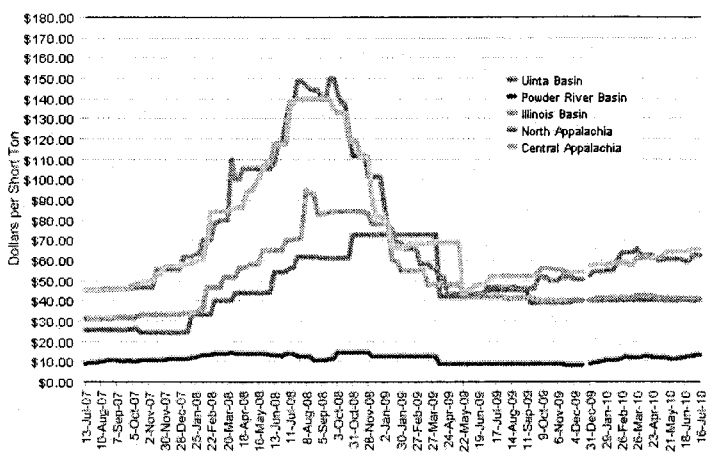
1. The decision in these proceedings will establish (separately for Base Resources and for Other Resources) a separate, unique base cost for each PRM and one common base cost for all ARMs (these factors are termed "power cost adjustor bases").
2. Each month, AEPCO will determine the amount of kWh that each member receives from Base Resources and from Other Resources.
3. Each month, AEPCO will determine a single overall cost per kWh for Base Resources for the month and a single overall cost per kWh for Other resources for the month.
4. AEPCO will determine each member's costs for the month (separately for Base Resources and for Other Resources) by multiplying the Base Resources and Other Resources receipts determined in Step 2 times the applicable rates for each resource type as determined in Step 4.
5. For purposes of calculating member costs, AEPCO will directly assign three categories of costs: (a) Southpoint and Griffith purchase and wheeling costs will be directly assigned to the ARMs (collectively) and to Trico, but not to the other PRMs, and (b) any future power purchase agreements joined into only by some members, and (c) costs and revenue credits associated with base resource transfers of power and energy among members and base resource economy sales to third parties.
6. AEPCO will then subtract from the costs determined for each member in Step 5 above the costs of the kWh receipts (from Step 2 above) at the base costs (from Step 1 above); this step produces separate determinations of each member's over- or undercollected Base Resources and Other Resources costs for the month.
7. AEPCO will enter each month's calculations of over- and undercollections in distinct "bank balancing accounts" for each member; each member will have a separate bank balancing account for Base Resources and for Other Resources.
8. Each member's two account balances will be set at zero upon the effective date of the new FPPAC; the FPPAC adjustor rates for all members will also begin at zero.
9. As is the case under the current FPPAC, AEPCO will calculate those adjustor rates twice per year (with filings to be made on each March 1 and September 1 for effectiveness, presumably remaining, as the current changes are, subject to Commission suspension).
10. AEPCO would make the first filing (to move the zero rate) on March 1, 2011, for effectiveness April 1, 2011.
11. The draft Plan for Administration calls for the same two-part adjustor rates, as does the current FFPAC; i.e., one part based on average monthly over- or undercollections (expressed as cents/kWh) across the preceding 12 months and the other based on recovering the bank balance (accumulated from inception of the new FPPAC) over six months. However, there would be separate two-part rates for Base Resource and Other Resource deliveries.

AEPCO will use its Billing Unit Model to itemize Base Resources and Other Resources sales (in both kWh and dollars) by member by month. This model will generate the detail required to support the various sales-amount and cost information necessary to support FPPAC calculations. AEPCO proposed to include in monthly compliance reports to the Commission the calculations of sales costs, and balances for each member. AEPCO anticipates, and Liberty concurs, that it will fall principally to the members to question the ability of the model to function correctly and to serve as the primary source for verifying correct application of all of the FPPAC requirements applicable to different member classes, to different resource types, and to individual member balances. [58]

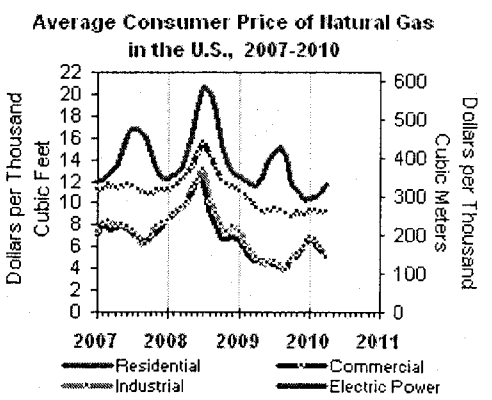
6. Fuel Price Volatility

The fuel and energy market volatility that drove the introduction of an FFPAC at AEPCO have not diminished. The following chart[59] from the U.S. Energy Information Administration shows the dramatic increases that electric utilities, among other coal users, have experienced in the very recent past. Increases in prices for coal from the Powder River Basin have been more moderate, but still significant. The sharp increases shown for the first part of 2009 have reversed, as the following chart demonstrates.[60] The scale of the second chart particularly masks the changes in Powder River Basin coal prices. The chart demonstrates that volatility has truly become a "two-way" street in the industry. Natural gas prices have also fluctuated greatly and fundamental, long-term changes in supply (Marcellus Shale[61] and imported LNG) have occurred. The following chart shows the dramatic recent changes in natural gas prices.[62]





A number of factors can be expected to continue affecting price certainty. Amid growing international demand for energy sources, world economic conditions remain very uncertain. The *Wall Street Journal*, for example, has just reported that China has surpassed the United States as the leading consumer of energy. Formerly an exporter of coal and oil, China is now aggressively engaged in locking up long-term sources of these fuels. Domestic markets for coal have already been affected by international demand, and this effect seems likely to continue. Natural gas has become much more competitive with coal, with utilities all across the country finding gas to be increasingly



displacing coal as a baseload generation source. Increasing renewable requirements have put new sources, such as wind, in what amounts to a "must run" location in the generation stack and the uncertain future of carbon reduction and capture also have significant potential to affect energy markets.

C. Conclusions

1. AEPCO's FFPAC has to date served to mitigate the effects of over and under collections of fuel and purchased power costs.

At the time of its adoption in 2005, the FPPAC responded effectively to the types of swings then characteristic and to be expected in AEPCO's energy markets. Some commissions had by then shown a preference for a shorter-term adjustment period (compared with the 12-month rolling average of AEPCO's adjustor), but the AEPCO approach was consistent with the range of current experience. The use of forecasted costs as the basis for adjustment clause calculation has also been increasing. Liberty did not, however, observe forecasting to be a strength of AEPCO. That observation supports reliance on historical data here. Other clauses also frequently include SO_2 allowance transaction net costs. The infrequency of AEPCO's allowance transactions and RUS requirements, however, also make the exclusion of their costs here appropriate.

Despite its successful history in recovering substantial differences between base and actual costs, however, changes in external forces and factors since the FPPAC's introduction have made it increasingly slow to respond to cost changes. The 2008 acceleration of recovery of undercollected balances helped materially.

2. Recent market dynamics suggest consideration of an FPPAC that will respond more quickly to cost changes, but AEPCO's circumstances require measured consideration of change. *(Recommendation #1)*

The Commission approved the acceleration of the FPPAC's "Bank Account" component in 2008 when undercollections totaled $4.9 million. The Commission recognized that this change would not eliminate the FPPAC's "lagging tendency," but deferred consideration of more fundamental change. The accuracy of the Commission's judgment is shown in the results following the acceleration. The balance dropped by about $0.5 million (10 percent) through the end of 2009. AEPCO advised that it has dropped much more substantially thereafter. These results appear to demonstrate that a continued fall in energy prices through 2009, and the sustaining of low prices through early 2010 (particularly for natural gas) has been a primary driver of the reduction in the undercollected balance. It is clear that, as the balance has been somewhat slow to decline in falling energy markets, so it would be slow to increase in rising markets. Nevertheless, recent experience and continuing global and national uncertainties make clear that the balance has the very real potential for reaching in the future the level that the Commission found to be of concern when it agreed to an accelerated balance amortization.

This concern has particular relevance for a cooperative generation enterprise. They tend to be significantly more thinly capitalized than their investor-owned utility counterparts. Entities such as AEPCO therefore have less ability to withstand significant undercollections of actual costs, even when their eventual recovery is highly likely. Cooperative G&Ts are also generally more

thinly capitalized than the distribution cooperatives they serve. Thus, as between supplier and purchaser, the latter is, all else equal, better positioned to accommodate cost recovery deferrals.

These factors suggest a more current method of recovery at the AEPCO level, with its members then left to decide, each for itself, what method (*e.g.*, a correspondingly rapid recovery method) to use to address the financial changes that prompter payment to AEPCO would generate. Two countervailing factors apply. First, Liberty's cost-of-capital recommendations in the current AEPCO rate proceedings would strengthen AEPCO's financial position for the short term at least. Second, with the number of cooperatives that AEPCO serves, a sudden change that does not give them time to plan and adjust could be disruptive. A strength of AEPCO's rate changing process is the dialogue with members (the "customers" who have to accommodate changed energy costs in their own planning, budgeting, and pricing) that precedes formal requests to the Commission. While discussions about the FPPAC have clearly taken place, it does not appear that they have included any planning to address a more current recovery method. Certainly the changes proposed do not call for any such alteration.

3. The changes that AEPCO has proposed to its FFPAC will serve to improve the alignment of cost causers and cost bearers, as between its all- and partial-requirements members.

AEPCO has experience material migration from all-requirements service. Future planning for power-supply resources in the region has also changed in a way that gives AEPCO's members significant flexibility in how they pursue future opportunities. AEPCO's efforts to refine its methods for allocating costs among members is appropriate, and extending those methods to its FPPAC are sound. The success of these efforts will depend on AEPCO's ability to measure generation costs accurately on an hourly basis. Verifying its successful implementation will take diligence on the part of the members. Their stakes in accurate assignment and allocation of costs provide comfort that any "shakeout" issues that may arise will be promptly identified and corrected.

4. AEPCO has not presented a specific method for closing out remaining balances under the current FPPAC and its proposed plan for administration, while generally sound, exhibits a lack of clarity in certain areas. *(Recommendation #2)*

AEPCO's supplemental response to Staff Data Request No. 1.61 provided a proposed Plan for Administration for its proposed, changed FPPAC. That proposed plan observed the need to design a temporary surcharge for collecting the bank balances attributable to the prior FPPAC, but remaining as of the effective date of the new clause. AEPCO advised that it had yet to design this mechanism.[63] That mechanism should be defined and in place by the effective date of the new FPPAC.

In addition, Liberty's review of the AEPCO proposed plan for administration disclosed some areas that would benefit from clearer expression. Should the Commission decide that the FPPAC should remain, the plan for implementing it should be reviewed with Staff to assure its consistency with the Commission order and with the need for the plan to be complete and clear.

D. Recommendations

1. **Address through focused discussions with the Class A members a change that will produce more current FPPAC recovery.** *(Conclusion #2)*

AEPCO and the members should convene a series of discussions designed to produce a recovery mechanism that will provide for recovery or refund of under and over collections under the FFPCA within a period of from one to three months. These discussions need to consider the need for the members to have the time necessary to make adjustments they deem appropriate in pricing to their end-use members. AEPCO and the Class A members should strive to present to the Commission a proposal within six months of the effective date of the new FPPAC.

2. **Assuming that AEPCO's proposed FPPAC continuation and changes are found by the Commission to be generally appropriate, establish a temporary surcharge mechanism, and clarify the proposed plan for administering it.** *(Conclusion #4)*

The balances accumulated under the old FPPAC and therefore they should be collected in a manner that is consistent with the member expectations about recovery that existed at the time the deferrals were accruing. The most direct means for recovery would be to continue the Bank Account feature of the current clause, which should provide for recovery to be complete (subject to final reconciliation at the end of six months, if there is a material variation in Member usage) within six months and in accord with the charging principles applicable under the current clause.

The Staff and AEPCO should also conduct a joint vetting process to assure mutual comfort with the clarity, completeness, and precision of the Plan for Administration as proposed by AEPCO.

[1] Minson Direct Testimony
[2] AEPCO 2009 Final Report.
[3] http://www.nationalcoaltransportation.org/
[4] Source: response to DR No. STF 4.4.
[5] Source: Adger telephone interview of Walter Bray, May 28, 2010.
[6] Response to DR No. 4.23.
[7] Responses to DR Nos. 4.4 and 4.46.
[8] The contract was provided in response to DR No. 7.9.
[9] This material is from the response to DR No. STF 11.5.
[10] This material comes from DRs No. STF 4.35 and 4.58, plus Adger's (telephone) interviews of Walter Bray and Gary Grimm on May 28 and July 20, 2010.
[11] Gary Grimm, May 28 and July 20, 2010.
[12] Gary Grimm, May 28 and July 20, 2010.
[13] Response to DR No. 11.3.
[14] Response to DR No. 7.6.
[15] Most of this material came from Adger's interviews (by phone) of Walter Bray on May 28 and July 15, 2010, supplemented by information from the Company's responses to DRs No. STF 4.2 and 4.5.
[16] Response to DR No. STF 4.40
[17] Source: ACES PM briefing provided in response to DR No. STF 4.48. It appears that this briefing was presented some time in 2007.
[18] This information is from Adger's telephone interview of Walter Bray on July 15, 2010.
[19] Response to DR No. STF 11.7.
[20] Relevant materials were provided to Liberty in response to DRs No. STF 4.3 and 4.8.
[21] Response to Data Request STF 8.13.
[22] Ibid.
[23] Response to STF 5.2, AEPCO interview regarding power trading on May 18, 2010.
[24] AEPCO interview regarding power trading on May 18, 2010.
[25] Interview with AEPCO Vice President, Power Resources and Planning, July 20, 2010.
[26] Responses to Data Requests 8.10 and 8.11.
[27] Responses to Data Requests 4.70 and 4.71.
[28] Interviews with AEPCO Vice President Power Resources & Planning on May 18 and July 20, 2010; responses to Data Requests 4.70 and 4.71.
[29] Interviews with AEPCO Vice President Power Resources & Planning on May 18 and July 20, 2010.
[30] Ibid.
[31] Responses to Data Requests 1.59 and 8.12.
[32] Interview with AEPCO Power Trading Desk personnel, July 20, 2010.
[33] Ibid, response to Data Request 8.13.
[34] Interview with AEPCO Power Trading Desk personnel, July 20, 2010.
[35] Interview with AEPCO real-time trader, July 20, 2010.
[36] Response to Data Request 8.12.
[37] Response to Data Request 4.60.
[38] Interview with the Manager, Power Trading, July 20, 2010.
[39] Interviews with AEPCO Manager, Power Trading and Steve Zwilling and Jean Nitz of ACES, May 17 and 18 2010.
[40] Response to Data Request 4.8.
[41] Response to Data Request 4.14.
[42] STF 4.99
[43] The source for all performance data is STF 4.59
[44] STF 10.19
[45] STF 10.18
[46] Generator Availability Data System - NERC
[47] STF 10.17

[48] STF 10.14 and 10.15
[49] STF 10.14
[50] STF 10.16
[51] STF 4.63, 4.98 and 10.13
[52] STF 10.6
[53] STF 10.6, and 10.8 through 10.11
[54] STF 10.7
[55] Differentials of $[redacted] MWh are used. STF 10.13 data suggests that [redacted] MWh has been exceeded only a few times with values under [redacted] MWH much more frequent.
[56] Pierson, King Phone Interview July 7, 2010.
[57] Pierson, King Phone Interview July 7, 2010.
[58] Pierson, King Phone Interview July 7, 2010.
[59] http://www.eia.doe.gov/cneaf/coal/page/special/images/fig7.jpg
[60] http://www.eia.doe.gov/cneaf/coal/page/coalnews/images/weekly2/weekly2.jpg
[61] http://geology.com/articles/marcellus-shale.shtml
[62] http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/natural_gas.html
[63] Telephone Interview with Pierson and King, July 7, 2010.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

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-01773A-09-0472

DIRECT

TESTIMONY

(PRUDENCE REVIEW)

OF

RICHARD MAZZINI

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 30, 2010

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ADMITTED

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Resume RAM-1

INTRODUCTION

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

A. My name is Richard Mazzini. I am an Executive Consultant associated with The Liberty Consulting Group ("Liberty"). My Liberty business address is: The Liberty Consulting Group, 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Mr. Mazzini, briefly summarize your education background and professional qualifications as they relate to the subject of your testimony.

A. I have been engaged as a consultant and utility manager in the electric utility industry since 1967. Until 1995, I was employed by Pennsylvania Power & Light Company in a variety of senior management positions. After entering the consulting business in 1995, I served in senior positions with Washington International Energy Group, Navigant Consulting and ABB. I have been an independent consultant since 2001. As a consultant, I have assisted utilities throughout the United States, Canada, the Caribbean and Europe and have worked on behalf of many utility regulatory authorities.

I have a B.E.E. degree from Villanova University and an M.S. degree in Nuclear Engineering from Columbia University. I am a Registered Professional Engineer in Pennsylvania and a member of the Institute of Electrical and Electronics Engineers and the American Nuclear Society.

Q. Have you prepared a more detailed summary of your background?

A. Yes; Exhibit RAM-1 provides it.

Q. What is the purpose of your testimony?

A. The testimony of John Antonuk examines the prudence of fuel, purchased power, and plant operations policies, activities, and costs of Arizona Electric Power Cooperative, Inc. ("AEPCO" or "the Cooperative"), and also summarizes the review of AEPCO's facilities from an engineering perspective. Liberty prepared a report addressing the findings, conclusions, and recommendations of that examination. The report is attached to Mr.

Antonuk's testimony as Exhibit JEA-2. I directly performed the work reflected in the Engineering Analysis/Plant Operations section (Chapter VII) of that report. The purpose of my testimony is to support and respond to questions regarding that portion of Exhibit JEA-2.

Q. Can you please briefly summarize the portion of the report for which you are responsible?

A. I was responsible for directly performing the engineering analysis of APECO's assets, which focused on the generating units, which form the core of those assets. Much of my work concentrated on the units of the Apache Station. Liberty examined generating unit performance, operations, maintenance, and capital improvements. Liberty reviewed existing maintenance practices, examined how AEPCO documents them, and reviewed management controls to ensure proper implementation and execution of those practices. Liberty also reviewed plant outages and conducted a review designed to determine the "used & useful" nature of rate-base assets. Liberty's review included a physical inspection at Apache Station and interviews with the personnel responsible for managing key functions at the plant.

Q. Does that conclude your direct testimony?

A. Yes it does.

Richard Mazzini Resume

Areas of Specialization

Management and regulatory audits; utility operations, including nuclear and other power production; power marketing and risk management; strategic planning; organization analysis and competitive re-structuring; project management; cost management; and tariff design and management.

Relevant Experience

The Liberty Consulting Group

Public Service Commission of New York – A management audit of Con Edison. Project Manager for a 13-member Liberty consultant team.

Maine Public Utilities Commission – Review and analysis of proposed new transmission project, the Maine Power Reliability Project ("MPRP"). Lead Consultant for economic analysis.

Public Service Commission of Maryland – Consultant supervising the various auctions for procurement of power for Maryland's standard offer service ("SOS") customers and support for the PSC in their analysis of new approaches to SOS supply.

Management Audits

Public Service Commission of New York – An operational audit of Con Edison's reliability and emergency response planning and processes. Lead Consultant for corporate strategy and priorities, emergency planning and organization.

Federal Energy Regulatory Commission (FERC) – A review of the California ISO. Examined governance issues, operating procedures, transmission planning and analysis, organizational issues, interfaces with stakeholders and recommendations for the restructuring of the California market.

City of Seattle (Washington) – Review of the City's utility, commissioned by City Council and the Office of City Auditor, to analyze financial strategies, power market and risk management strategies and governance schemes. Lead Consultant for risk management.

St. Vincent Electricity Services, Ltd. – A management audit commissioned by the Board of Directors. Scope included generation, transmission, distribution, organizational assessment, safety, procurement and fuel.

New Jersey Bureau of Public Utilities – Evaluation of the gas supply and hedging programs of the four New Jersey gas distribution companies.

New York Power Authority – Consulting support for an internally sponsored audit of energy risk management functions.

Strategic Business Planning

Barbados Light & Power Company – Project Manager and Lead Consultant for a strategic planning initiative. Major areas of attention included new generation options, regulatory strategies, competitive threats, tariff design, new business opportunities, human resource issues, and planning processes.

Barbados Light & Power Company – Project Manager and Lead Consultant for the development of a model for the risk analysis of various new generation investments.

Electricité de France – Provided business planning and analysis services in the furtherance of the utility's wholesale and retail businesses. The work included research and analysis of potential gas partnerships, trading alliances and development of new retail markets throughout Europe.

SaskPower (Saskatchewan) – Project Manager and Lead Consultant for development of a strategic plan for the Power Production Business Unit. The project included asset valuation and optimization, transmission plans and strategies, efficiency improvement, market analysis and organizational options.

Omaha Public Power District – Project Manager and Lead Consultant for an extensive strategic business planning initiative. This multi-phase project spanned one year and included (1) asset evaluation, estimation of potential stranded costs and stranded cost mitigation strategies; (2) business growth strategies, including retail retention and expansion, new products and services, new utility businesses, wholesale marketing and bulk power trading; (3) corporate restructuring through the formation of four new business units; (4) organization design, including the creation of two new marketing organizations and a new trading floor; and (5) regulatory and legislative strategy development.

Omaha Public Power District – Project Manager and Lead Consultant for a follow-up analysis to the above project a year later to recommend added steps and course corrections. Provided new recommendations on organization design, customer service,

stranded costs, energy marketing and trading initiatives, risk management, new business development, new products and services and strategic planning processes.

A Large Canadian Provincial Electric Utility – Strategic planning and business support in the analysis of future generation and transmission options associated with a major new generation construction project.

Tennessee Valley Public Power Association – Project Manager and Lead Consultant for development of a comprehensive new business strategy that reinvented the Association for a competitive environment. Key elements of the plan included a new expanded focus on government relations and the influencing of public policy, as well as the creation of four newly created business units and business endeavors.

City Council of Los Angeles (California) – Advice to the Council on the strategic plans of its municipal electric utility. Conduct of a workshop for the Council and staff on restructuring and competitive issues. Review of power marketing alliance strategies.

Riverside Public Utilities (California) – Analysis of the potential to sell all or part of the utility. Development of a new business vision and strategy. Analysis of outsourcing and alliance possibilities. Development of a power supply alliance, including design of the venture, development of RFP, evaluation of bidders, selection of finalist and negotiations. Organizational design and implementation. Planning and project management support for activities leading to open access.

Lower Colorado River Authority – Consulting support for strategic review and development of alliance strategies. Facilitation of management workshop to develop strategic responses to key issues and to examine options for strategic alliances.

ElectriCities of North Carolina – Business simulations and strategic planning for the North Carolina Power Agencies.

ElectriCities of North Carolina – Analysis of the Carolina P&L – Florida Progress merger with resulting strategies and negotiations on behalf of ElectriCities.

4–County Electric Cooperative – Strategic planning support for the Chief Executive Officer and Board of Directors. Designed and facilitated a planning workshop for the Board of Directors and key managers. Followed up with subsequent action plan for the Board.

Project and Cost Management

Omaha Public Power District ("OPPD") – Lead Consultant responsible for design and implementation of a cost management program for a major overhaul of the Fort Calhoun

Station. This $400 million project involved replacement of the two steam generators, pressurizer and reactor vessel head.

Power Marketing, Procurement and Risk Management

Public Service Commission of Maryland – Consultant supervising the various auctions for procurement of power for Maryland's SOS customers and support for the PSC in their analysis of new approaches to SOS supply.

Electricité de France – Supporting services for the implementation of a large trading and marketing alliance in Europe, including reporting and control processes and training workshops for employees.

SaskPower – Project Manager and Lead Consultant for the expansion of the bulk power marketing program and creation of an energy trading floor. Work included extensive recommendations on corporate structure, organization, trading and marketing strategies, trading floor characteristics, management controls, risk management strategies, training, alliance building and external interfaces.

Public Service Commission of Maryland – Provided consulting support to the PSC in the approval of the settlement agreement relating to SOS.

New Businesses

BGE Corporation (Constellation Nuclear Services) – Project Manager and Lead Consultant for the business analysis, planning, design and startup of a new subsidiary business for the client. The business, provision of nuclear related services to U.S. and international utilities, was successfully started in July 1999.

Electricité de France – Provided support in the planning, analysis, structure and negotiation of a large international energy trading and marketing alliance (EDF Trading, based in London).

Tennessee Valley Public Power Association – Project Manager and Lead Consultant for a survey and analysis of the Association's more than 150 member utilities. Produced an analysis with recommendations for the products and services that can best serve the members in a deregulated environment.

Municipal Electric Association (Ontario) – Project Manager and Lead Consultant for the development of a definitive business plan for a new power procurement business on behalf of the Association's more than 250 municipal electric utilities. Work included initial feasibility assessments followed by a complete actionable plan for the creation of the new organization, including structure, organization, staffing, financing, market

analysis, contingency plans, product offerings and promotional strategies. The resulting new company became a reality in late 1997.

ENERconnect (Ontario) – Served as interim Vice President of Marketing and Customer Service for the startup of this new power procurement and services company. Project Manager and Lead Consultant for the development of a detailed operational plan for startup. Assisted in all aspects of startup including organizational design, business strategies, product design and development and support to executive management and the Board.

ABB Energy Solution Partners – Consulting support for ESP-sponsored projects, including customer and project research, project structure, energy supply options, alliances and preparation of proposals. Included regulatory research and discussions in Nevada, Michigan, New Jersey and New York.

Ambient Corporation – Consulting support for strategic and tactical business planning for this startup firm specializing in power line communications ("PLC"), including development of commercialization plan and supporting management processes, support of business plan, product and service development, regulatory strategies and financing documentation.

PacifiCorp – Customer research with two groups of large industrial and commercial customers. Designed and managed interactive workshops to obtain their input, served as subject matter expert for the sessions, produced and presented comprehensive analyses of the results with strategic insights for the client's marketing initiatives.

T&D Support

Alberta Electric System Operator – Analysis of transmission loss methodologies for the Alberta market.

A Large Canadian Provincial Electric Utility – Business planning support for the transmission business unit. Analysis of the business potential of new transmission opportunities. Analysis of U.S. transmission policies and their potential impact on a Canadian player in the U.S. markets.

Utility Management

Pennsylvania Power & Light Company – Served in a variety of management positions in a long career with the utility. Responsible for strategic business planning, rates, bulk power marketing, system operation, management of non-utility generation contracts, rate design, market research and contract negotiations with large customers. Key

management roles in cost management, planning and scheduling for all Susquehanna nuclear station design, licensing, and startup activities including outage management.

Other Consulting Positions

Senior Vice President for ABB Energy Consulting, responsible for managing consulting engagements for a variety of U.S. and European energy firms.

Principal for Navigant Consulting, Inc., involved in numerous consulting engagements serving the electric utility industry in competitive initiatives.

Senior Vice President for the Washington International Energy Group, responsible for the firm's competitive positioning practice.

Education

M.S., Nuclear Engineering, Columbia University
B.E.E., cum laude, Villanova University

Registrations

Registered Professional Engineer – Pennsylvania

Memberships

Institute of Electrical and Electronics Engineers
American Nuclear Society

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
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BOB STUMP
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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-01773A-09-0472

DIRECT

TESTIMONY

(PRUDENCE REVIEW)

OF

RANDALL VICKROY

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 30, 2010

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ADMITTED

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INTRODUCTION

Q. State your name, position, and business address.

A. My name is Randall Vickroy. I am a senior consultant associated with The Liberty Consulting Group ("Liberty"). My Liberty business address is: The Liberty Consulting Group, 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Are you the same Randall Vickroy who has already provided direct testimony on cost of capital in this proceeding on July 2, 2010?

A. Yes, I am.

Q. Does that other testimony address your background insofar as it is relevant to the purposes of the following testimony?

A. Yes, it does.

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

A. The testimony of John Antonuk describes Liberty's examination of the prudence of Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "the Cooperative"), fuel, purchased power, and plant operations policies, activities, and costs. It's also a review of AEPCO's facilities from an engineering perspective. The findings, conclusions, and recommendations of that examination are attached to Mr. Antonuk's testimony as Exhibit JEA-2. I directly performed the work reflected in the Power Transactions portion (Chapter VII) of that report. The purpose of my testimony is to support and respond to questions regarding that portion of Exhibit JEA-2.

Q. Can you please briefly summarize the portion of the report for which you are responsible?

A. I was responsible for the direct performance of Liberty's review of APECO's power transactions. This review included examinations of: AEPCO's processes and models for forecasting power purchase requirements, its basis for soliciting long- and short-term purchases and sales and the effectiveness with which it has made and administered them, power purchase and sale costs, real-time trading and dispatch modeling and effectiveness.

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
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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-01773A-09-0472

SURREBUTTAL

TESTIMONY

OF

JOHN ANTONUK

(CONSULTANT)

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

SEPTEMBER 21, 2010

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John Antonuk. My business address is 65 Main Street, P.O. Box 1237, Quentin, PA 17083.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously submitted direct testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission"), Utilities Division Staff ("Staff"). It addressed Liberty's examination of the prudence of fuel, purchased power, and plant operations policies, activities, and costs of Arizona Electric Cooperative Inc.'s ("AEPCO") in connection with AEPCO's request for a general rate increase in the proceeding at Docket No. E-01773A-09-0472.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to AEPCO witness Pierson's rebuttal testimony addressing Liberty's review.

II. AEPCO'S RESPONSE TO LIBERTY'S PRUDENCE REVIEW

Q. Please summarize your view of AEPCO's responsiveness to the recommendations resulting from Liberty's review.

A. Staff found AEPCO highly receptive to making a number of the changes recommended by Liberty and to examining the benefits of implementing virtually all of the remaining recommendations. Staff believes after reviewing Mr. Pierson's testimony, as Staff believed during our frequent interactions with AEPCO personnel during the conduct of our review that AEPCO has demonstrated a sincere and reflective interest in using the results of our review as a complement to its own identification of needs and actions to optimize

performance for members. Staff found AEPCO's receptiveness to outside contributions to performance improvement notable at the time and Staff believes that Mr. Pierson's rebuttal testimony underscores that view.

Q. What has been your experience in the performance of other reviews of management and operations prudence and effectiveness?

A. Over a period that now spans two decades, we have performed more than 20 such reviews for utility regulatory authorities. This work covers a wide variety of utility operations types and ownership models.

Q. From that experience, what would you expect to be the process for implementing recommendations of the type that AEPCO has either agreed to make or to study and analyze?

A. The overwhelming majority of our work of this type has come outside the context of rate proceedings, where substantive communication is through highly formalized testimony filings. What we would generally see in those contexts is the preparation of an implementation plan and schedule by the utility. That plan would identify with reasonable particularity the implementation or study steps to be taken and a schedule for each. It is a frequent, but not universal, practice for the utility to provide periodic progress reports to its regulatory authority. These reports identify progress against the schedule and they discuss any implementation difficulties found, the results of studies or analyses to be completed before identification of specific implementation steps, and any changes to implementation plans or schedules identified as appropriate.

Such reports aid the utility in effectively planning and implementing change, and they keep regulators informed about the effectiveness and timeliness of changes agreed to be appropriate and about progress on matters where implementation planning depends on identified prior analysis.

III. AUDIT IMPLEMENTATION RECOMMENDATIONS

Q. What is Staff's recommendation?

A. Staff recommends the preparation of such an action plan by AEPCO, with quarterly reports to its board of directors. Staff recommends that AEPCO file copies of those reports with Commission, and encourage periodic discussions with Staff about implementation progress, any implementation difficulties found or changes made. Given the commitment of AEPCO to make and to consider a broad range of changes, Staff believes that this approach will speed implementation and enhance the benefits that we believe implementation will bring.

IV. PPFAC RECOVERY LAG

Q. Do you have any material uncertainties about any of Liberty's recommendations in light of AEPCO's response?

A. Yes. At page 16 of his rebuttal testimony, Mr. Pierson proposed that the issue of lag in AEPCO recovery of fuel and purchased power costs be dealt with as part of the efficacy review of the last rate order. As Mr. Vickroy's testimony on cost of capital indicates and he is prepared to respond to at hearings, we have concern about the ability of AEPCO to withstand significant and sudden changes that may affect its margins, cash flow and financial health and responsiveness. He has specifically noted fuel price volatility as a risk to AEPCO's financial status, along with the financing costs of capital expenditures since the test period and increases in operating expense items such as mercury control chemicals.

We have all seen the magnitude of the cost changes that can come quickly to the electricity

supply industry and, unfortunately, the great consequence those changes can produce when times are uncertain from a financial perspective as well.

AEPCO's unrecovered balance has been declining in recent months. However, Staff does not believe that recent conditions lessen the need to be concerned about volatility in energy markets.

The concerns underlying Staff's PPFAC lag and cost-of-capital recommendations have much in common. Specifically, fuel and energy volatility form a primary concern about the ability of AEPCO to withstand financial reverses. The combination of AEPCO's lower proposed DSC ratio and the recovery lag remain of concern. Accordingly, at this point, Staff continues to propose the DSC of 1.40 proposed by Mr. Vickroy, although we do find acceptable the PPFAC recommendation of Mr. Pierson's rebuttal testimony.

Q. Does that conclude your surrebuttal testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
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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-01773A-09-0472

SURREBUTTAL

TESTIMONY

OF

RALPH C. SMITH

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

SEPTEMBER 21, 2010

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EXECUTIVE SUMMARY
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Staff's surrebuttal testimony acknowledges the acceptance of Staff's recommended rate base, and adjusted net income by Arizona Electric Power Cooperative, Inc. ("AEPCO"). A difference remains in Staff's recommended revenue increase and AEPCO's request, which is due to Staff using the debt service coverage ("DSC") method and applying the DSC ratio of 1.40 recommended by Staff witnesses Vickroy (direct) and Antonuk (surrebuttal), whereas AEPCO, in its rebuttal testimony is requesting a DSC ratio of 1.32 (increased from AEPCO's previously recommended DSC of 1.275).

Staff also addresses AEPCO's updated information concerning rate case expense and concludes that the annual allowance of $160,000 used in AEPCO's direct and rebuttal filings and in Staff's calculation of the AEPCO's operating expenses represents a reasonable normalized amount.

I. INTRODUCTION

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

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted direct testimony in this proceeding on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. What is the purpose of the surrebuttal testimony you are presenting?

A. The purpose of my surrebuttal testimony is to address the application for a general rate increase filed by Arizona Electric Power Cooperative, Inc. ("AEPCO" or "Company"). Specifically, Staff will be addressing the revenue requirement, rate base, and net operating income and respond to certain issues addressed in the rebuttal testimony of AEPCO witness Gary Pierson.

II. RATE BASE, ADJUSTED OPERATING INCOME AND REVENUE REQUIREMENT

Q. Has AEPCO agreed with Staff's recommended adjusted fair value rate base and adjusted operating income?

A. Yes. At pages 1 and 2 of his rebuttal testimony, Mr. Pierson indicates that AEPCO has accepted each of the rate base and operating income adjustments that Staff had recommended in direct testimony. Mr. Pierson states that AEPCO has accepted Staff's proposed rate base of $211.8 million, which was set forth in Attachment RCS-2, page 4, to my direct testimony, as the fair value rate base. He states further that AEPCO also accepts Staff's test year adjusted revenues of approximately $178.8 million, operating expenses of

$162.8 million, electric operating income (margins) of $15.9 million, and net margins in the test year of $5.2 million, as set forth in Attachment RCS-2, page 2, column D, to my direct testimony.

Q. Has AEPCO recommended any revision to the normalized annual allowance for rate case expense used by AEPCO and Staff to compute the adjusted net operating income?

A. No. AEPCO has not requested any revision to the $160,000 normalized annual allowance for rate case expense, which has been used in AEPCO's direct and rebuttal filings and by Staff in Staff's direct filing to compute adjusted operating income.

Q. Please discuss the follow-through issue concerning the normalized allowance for rate case expense that was addressed in AEPCO's rebuttal testimony.

A. In Staff's direct testimony Staff had questioned why the annual allowance for AEPCO's rate case expense should be so much higher than the comparative amount for Southwest Transmission Cooperative ("SWTC"). Mr. Pierson's rebuttal testimony on page 2 presents additional information indicating that AEPCO's actual and expected rate case expenses are exceeding its initial estimate.[1] Staff is satisfied with Mr. Pierson's explanation on page 3 of his rebuttal testimony concerning why the normalized rate case expense for AEPCO is and should be higher than the comparative annual rate case expense allowance for SWTC.

[1] As noted above, AEPCO is not requesting any adjustment from the normalized annual allowance for rate case expense of $160,000 that has been used by both AEPCO and Staff.

Q. Are there any other clarifications that you would like to make concerning the normalized annual allowance for rate case expense?

A. Yes. Staff views the $160,000 that has been used by Staff and accepted by AEPCO as a normalized annual expense allowance amount, not an amortization of a capitalized and deferred amount. Accordingly, on its books, AEPCO should not attempt to capitalize and defer any rate case expense.

Q. You have indicated that AEPCO agrees with Staff's proposed rate base and adjusted net operating income. Is there any revenue requirement recommendation difference between AEPCO and Staff, and if so, why?

A. Yes. As shown on Mr. Pierson's rebuttal Exhibit GEP-2, a difference remains in AEPCO's revised request of a revenue decrease of $1,172,317 and Staff's recommended revenue increase of $231,014. This difference is attributable entirely to Staff using the debt service coverage ("DSC") method and application of the DSC ratio of 1.40 recommended by Staff witnesses Vickroy (direct) and Antonuk (surrebuttal), whereas AEPCO, in its rebuttal testimony is requesting a DSC ratio of 1.32 (increased from AEPCO's previously recommended DSC of 1.275). The DSC recommended by Staff of 1.40 and the DSC recommended by AEPCO in Mr. Pierson's rebuttal testimony of 1.32 are both within the "range of reasonableness" necessary to maintain investment grade credit ratings of 1.25 to 1.45 recommended in Staff witness Vickroy's direct testimony. Mr. Antonuk's surrebuttal testimony presents Staff's reasoning for continuing to recommend the DSC of 1.40 in this case.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
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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-01773A-09-0472

SURREBUTTAL

TESTIMONY

OF

DENNIS M. KALBARCZYK

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

SEPTEBMER 21, 2010

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ADMITTED

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DMK Schedule G-1 - Surrebuttal: Cost of Service Summary – Present Rates
DMK Schedule G-2 - Surrebuttal: Cost of Service Summary – Proposed Rates

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dennis M. Kalbarczyk. My business address is 910 Piketown Road, Harrisburg, Pennsylvania 17112.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously submitted direct testimony on behalf of the Arizona Corporation Commission ("ACC" or "Commission"), Utilities Division Staff ("Staff"). It addressed my review of the application by Arizona Electric Power Cooperative Inc. ("AEPCO" or "Cooperative") for a general rate increase in the proceeding at Docket No. E-01773A-09-0472.

Q. What is the purpose of your surrebuttal testimony?

A. Staff surrebuttal testimony responds to AEPCO witness Goble's rebuttal testimony addressing his fully allocated cost of service and rate design recommendations. His revised fully allocated cost of service study and proposed rate design (GLG-Schedules G and H) incorporates AEPCO's revised overall revenue requirements, which Mr. Pierson's rebuttal testimony provides. Mr. Goble also reflects changes in allocation factors and rates to reflect Mr. Pierson's rebuttal testimony. Mr. Pierson's rebuttal testimony discusses the decision of Trico Electric Cooperative ("Trico") to change from an all-requirement member ("ARM") to a partial-requirements member ("PRM").

Staff also presents revised fully allocated cost of service study and proposed rate design (DMK -Schedules G and H Surrebuttal). Staff accepts AEPCO witness Goble's methods for separating the costs of serving Trico as a PRM from the three remaining ARM's, which he

refers to as "Collective All-Requirement Members" ("CARM"). I have incorporated those methods into my cost of service study and rate design recommendations.

II. ALLOCATED COST OF SERVICE STUDY AND RATE DESIGN

Q. Please describe AEPCO's revised allocated Cost of Service study and proposed rate design proposal.

A. Mr. Goble and Staff I are in general agreement with the methods of AEPCO's cost of service study approach. AEPCO accepted all of Staff Witness Smith's expense adjustments and Witness Goble has accepted my cost allocation methods used to allocate the Smith adjustments (at page 2). Mr. Gobel's rebuttal testimony (at pages 3-5) explains that he made revisions to his allocation study to reflect Trico's decision to change from ARM to PRM status.[1] The methods he explains and that he used in separating cost responsibilities follows his original approach. His updated study merely incorporates the updated service requirements for each of the respective ARM and PRM customer classes to that of the sum total requirements.

Mr. Gobel's cost allocation study and rate design also incorporate the $177,590,362 of revised revenue requirements advanced by AEPCO witness Pierson in his rebuttal testimony, $165,446,322 of those requirements would be derived from proposed rates.

Q. Describe your understanding of Staff's position with regard to the overall revenue requirement in the instant proceeding.

A. AEPCO has accepted all of Staff Witness Smith's expense adjustments; however, AEPCO has not accepted Staff's proposed margin level requirements. Thus, Staff's recommended revenue requirement of $178,993,694 of which $166,849,654 would be derived from

[1] My direct testimony noted, at pages 12-13, that Trico's amended agreements were filed on June 2, 2010 and I reserved the ability to comment on any impact on cost of service and rate design matters at a later date.

proposed rates, remains unchanged. Thus, my revised fully allocated cost of service study and proposed rate design (DMK- Schedules G and H Surrebuttal) merely incorporates the change in rate design due to the change in Trico moving from ARM to PRM status.

Q. Please summarize AEPCO's rebuttal and Staff's surrebuttal revenue requirement positions.

A. The following table summarizes AEPCO's and Staff's adjusted current and proposed test year revenues, operating expenses, net income (margins), and overall rates of return under current and proposed rates.

Table I – Cost of Service Summary

	AEPCO Rebuttal		Staff Surrebuttal	
Revenues	**Current**	**Proposed**	**Current**	**Proposed**
Electric Member Revenue	$166,618,638	$165,446,321	$166,618,638	$166,849,654
Non-Members	8,620,097	8,620,097	8,620,097	8,620,097
Other Operating Revenue	3,523,943	3,523,943	3,523,943	3,523,943
Total Operating Revenue	$178,762,678	$177,590,361	$178,762,678	$178,993,694
Operating Expenses	162,820,300	162,820,300	162,820,300	162,820,300
Operating Income (Margin)	$ 15,942,378	$ 14,770,061	$ 15,942,378	$ 16,173,394
Income Taxes	-	-	-	-
Net Income (Margin)	$ 15,942,378	$ 14,770,061	$ 15,942,378	$ 16,173,394
Rate Base	$211,802,594	$211,802,594	$211,802,594	$211,802,594
Rate of Return	7.53%	6.97%	7.53%	7.64%

Q. Please summarize AEPCO's rebuttal and Staff's surrebuttal proposed rate design?

A. The following table compares AEPCO's rebuttal and Staff's surrebuttal proposed rates to that of current rates, and shows the percentage increase under those proposals. The table also reflects Trico's move from an ARM to PRM customer; it denotes the remaining ARMs as CARM while Trico is listed separately as a PRM customer.

Table II- Current and Proposed AEPCO/STAFF RATES WITH % INCREASE					
		AEPCO Rebuttal		STAFF Surrebuttal	
Services	Current	Proposed	% Inc.	Proposed	% Inc.
CARM Charges					
Demand Rate ($/kW)	$14.98	N/A		N/A	
Fixed Charge		$238,793		$251,168	
O&M Charge		$414,019		$414,019	
Energy: Base Resources ($/kWh)		$0.03156		$0.03156	
Energy: Other Existing Resources ($/kWh)		$0.06170		$0.06170	
Energy: Average ($/kWh)	$0.02073	$0.032791		$0.032791	
ARM Revenues	$15,938,195	$15,564,588	-2.34%	$15,713,095	-1.41%
Revenue Increase/(Decrease)		($373,607)		($225,100)	
PRM Charges - Mohave Elec. Coop					
Fixed Charge	$855,113	$ 727,283		$ 764,976	
O&M Charge (Current $/kW)	$7.26	$1,274,882		$1,274,882	
Energy: Base Resources ($/kWh)		$0.03215		$0.03215	
Energy: Other Existing Resources ($/kWh)		$0.06879		$0.06879	
Energy: Average ($/kWh)	$0.02073	$0.035943		$0.035943	
PRM Revenues MEC	$54,205,506	$55,489,632	2.37%	$55,941,934	3.20%
Revenue Increase/(Decrease)		$1,284,127		$1,736,428	
PRM Charges – Sulphur Springs VEC					
Fixed Charge	$757,429	$ 643,991		$ 677,366	
O&M Charge (Current $/kW)	$7.26	$1,128,876		$1,128,876	
Energy: Base Resources ($/kWh)		$0.03229		$0.03229	
Energy: Other Existing Resources ($/kWh)		$0.06676		$0.06676	
Energy: Average ($/kWh)	$0.02073	$0.036711		$0.036711	
PRM Revenues SSVEC	$52,026,365	$52,370,038	0.66%	$52,770,540	1.43%
Revenue Increase/(Decrease)		$343,673		$744,175	
PRM Charges – Trico Electric Cooperative					
Demand Rate ($/kW)	$14.98	N/A		N/A	
Fixed Charge		$ 646,435		$679,937	
O&M Charge (Current $/kW)		$764,465		$764,465	
Energy: Base Resources ($/kWh)		$0.03238		$0.03238	
Energy: Other Existing Resources ($/kWh)		$0.06604		$0.06604	
Energy: Average ($/kWh)	$0.02073	$0.038824		$0.038824	
PRM Revenues SSVEC	$44,448,572	$42,022,063	-5.46%	$42,424,084	-4.55%
Revenue Increase/(Decrease)		($2,426,509)		($2,024,487)	
Total Electric Member Revenues	$166,618,638	$165,446,322	-0.70%	$166,849,654	0.14%
Revenue Increase/(Decrease)		($1,172,317)		$231,015	

Q. Please summarize your opinion as to AEPCO's above referenced revised fully allocated Cost of Service study and rate design surrebuttal proposal.

A. Staff has no objection to AEPCO's revised fully allocated cost of service study methods. Thus, I have revised my fully allocated cost of service study methods to incorporate AEPCO's revisions to its allocation study to reflect Trico's decision to move from ARM to PRM status. With that exception, my updated study incorporates the same revenue requirement position as provided for in Staff's direct testimony. The results of my updated study are attached as DMK-Schedules G and H Surrebuttal, respectively. In order to provide for ease of comparison, I continued to use the same Schedule G and H references as those in my direct testimony. DMK- Schedule A-1 Surrebuttal provides a proof of revenue by rate class. It demonstrates that Staff's proposed rates and other revenues will produce approximately the same $231,015 revenue increase as supported by Staff witness Smith's direct testimony.

For the reasons noted herein, Staff recommends adoption of Staff's proposed rates as summarized in my surrebuttal testimony at Table II above.

Q. Does that conclude your direct testimony?

A. Yes it does.

Arizona Electric Power Cooperative, Inc.

COST OF SERVICE SUMMARY - PRESENT AND PROPOSED RATES - AEPCO vs. Staff Adjusted

		Current		AEPCO REBUTTAL Proposed		Staff SURREBUTTAL Proposed
Collective All-Requirements Members						
Demand Rate per kW	$	14.98				
Fixed Charge			$	238,793	$	251,168
O&M Charge			$	414,019	$	414,019
Energy Rates						
Base Resources $/kWh			$	0.03156	$	0.03156
Other Existing Resources $/kWh			$	0.06170	$	0.06170
Energy Rate $/kWh	$	0.02073	$	0.032791	$	0.032791
Revenues	$	15,938,195	$	15,564,588	$	15,713,095
$Increase			$	(373,607)	$	(225,100)
% Increase				-2.34%		-1.41%
Partial-Requirements Members:						
Mohave Electric Cooperative						
Fixed Charge	$	855,113	$	727,283	$	764,975
O&M Charge (Present $/kW)	$	7.26	$	1,274,882	$	1,274,882
Energy Rates						
Base Resources $/kWh			$	0.03215	$	0.03215
Other Existing Resources $/kWh			$	0.06879	$	0.06879
Energy Rate $/kWh	$	0.02073	$	0.035943	$	0.035943
Revenues	$	54,205,506	$	55,489,632	$	55,941,934
$Increase			$	1,284,127	$	1,736,428
% Increase				2.37%		3.20%
Sulphur Springs Valley						
Fixed Charge	$	757,429	$	643,991	$	677,366
O&M Charge (Present $/kW)	$	7.26	$	1,128,876	$	1,128,876
Energy Rates						
Base Resources $/kWh			$	0.03229	$	0.03229
Other Existing Resources $/kWh			$	0.06676	$	0.06676
Energy Rate $/kWh	$	0.020730	$	0.036711	$	0.036711
Revenues	$	52,026,365	$	52,370,038	$	52,770,540
$Increase			$	343,673	$	744,175
% Increase				0.66%		1.43%
TRICO Electric Cooperative *						
Demand Rate per kW	$	14.98				
Fixed Charge			$	646,435	$	679,937
O&M Charge (Present $/kW)			$	764,465	$	764,465
Energy Rates						
Base Resources $/kWh			$	0.03238	$	0.03238
Other Existing Resources $/kWh			$	0.06604	$	0.06604
Energy Rate $/kWh	$	0.020730	$	0.038824	$	0.038824
Revenues	$	44,448,572	$	42,022,063	$	42,424,084
$Increase			$	(2,426,509)	$	(2,024,487)
% Increase				-5.46%		-4.55%
Total	$	166,618,638	$	165,446,322	$	166,849,654
$Increase			$	(1,172,317)	$	231,015
% Increase				-0.70%		0.14%

*TRICO Current Rates as ARM - Proposed Rates as PRM

SURREBUTTAL

Arizona Electric Power Cooperative, Inc.

COST OF SERVICE SUMMARY - PRESENT RATES - AEPCO vs. Staff Adjusted

LINE NO.	DESCRIPTION	PER AEPCO TOTAL AEPCO	PER STAFF TOTAL AEPCO	REBUTTAL PER AEPCO TOTAL AEPCO	SURREBUTTAL PER STAFF TOTAL AEPCO
1	REVENUES:				
2	MEMBERS (a)	$166,618,638	$166,618,638	$166,618,638	$166,618,638
3	NON-MEMBERS (b)	8,620,097	8,620,097	8,620,097	8,620,097
4	OTHER OPERATING REVENUE (b)	3,523,943	3,523,943	3,523,943	3,523,943
5	TOTAL REVENUES	$178,762,678	$178,762,678	$178,762,678	$178,762,678
6	OPERATING EXPENSES (c)	164,623,662	162,820,300	162,820,299	162,820,300
7	ELECTRIC OPERATING MARGINS	$14,139,016	$15,942,378	$15,942,379	$15,942,378
8	INCOME TAXES	0	0	0	0
9	RETURN (MARGINS) (LINE 7 - LINE 8)	$14,139,016	$15,942,378	$15,942,379	$15,942,378
10					
11	RATE BASE (d)	$ 231,844,975	$ 211,802,594	$ 211,802,594	$ 211,802,594
12	RATE OF RETURN	6.10%	7.53%	7.53%	7.53%
13					
14					
15	SUPPORTING SCHEDULES:				
16	(a) AEPCO & Staff (DMK) H-1, LINE 1				
17	(b) AEPCO C-1, PAGE 3, LINES 3 AND 5				
18	(c) AEPCO & Staff (DMK) G-6, PAGE 1, LINE 50 AND C-1, PAGE 4, LINE 44				
19	(d) AEPCO B-1, LINE 9 & Staff Attachment RCS-2, Page 2, Line 33 Staff Proposed Rate Base				

SURREBUTTAL

Arizona Electric Power Cooperative, Inc.

COST OF SERVICE SUMMARY - PROPOSED RATES - AEPCO vs. Staff Adjusted

LINE NO.	DESCRIPTION	PER AEPCO TOTAL AEPCO	PER STAFF TOTAL AEPCO	REBUTTAL PER AEPCO TOTAL AEPCO	SURREBUTTAL PER STAFF TOTAL AEPCO
1	REVENUES:				
2	MEMBERS (a)	$166,521,885	$165,446,322	$165,446,321	$166,849,654
3	NON-MEMBERS (b)	8,620,097	8,620,097	8,620,097	8,620,097
4	OTHER OPERATING REVENUE (b)	3,523,943	3,523,943	3,523,943	3,523,943
5	TOTAL REVENUES	$178,665,925	$177,590,362	$177,590,361	$178,993,694
6	OPERATING EXPENSES (c)	164,623,662	162,820,300	162,820,299	162,820,300
7	ELECTRIC OPERATING MARGINS	$14,042,263	$14,770,062	$14,770,062	$16,173,394
8	INCOME TAXES	0	0	0	0
9	RETURN (MARGINS) (LINE 6 - LINE 7)	$14,042,263	$14,770,062	$14,770,062	$16,173,394
10					
11	RATE BASE (d)	$ 231,844,975	$ 211,802,594	$ 211,802,594	$ 211,802,594
12	RATE OF RETURN	6.06%	6.97%	6.97%	7.64%
13					
14					
15	SUPPORTING SCHEDULES:				
16	(a) AEPCO & Staff (DMK) H-1, LINE 1				
17	(b) AEPCO C-1, PAGE 3, LINES 3 AND 5				
18	(c) AEPCO & Staff (DMK) G-6, PAGE 1, LINE 50 AND C-1, PAGE 4, LINE 44				
19	(d) AEPCO B-1, LINE 9 & Staff Attachment RCS-2, Page 2, Line 33 Staff Proposed Rate Base				

SURREBUTTAL

Arizona Electric Power Cooperative, Inc.

DERIVATION OF PROPOSED RATES - Staff Adjusted

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1					
2		SEE DMK SCHEDULE G-4, PAGE 1 OF 2			

SURREBUTTAL

Arizona Electric Power Cooperative, Inc.

RATE BASE ALLOCATION TO CLASSES OF SERVICE - Staff Adjusted

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO
1					
2		THIS SCHEDULE IS NOT APPLICABLE			

Arizona Electric Power Cooperative, Inc.

DERIVATION OF REVENUE REQUIREMENTS AND RATES - Staff Adjusted

LINE NO.	FUNCTIONAL COSTS	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO	TRICO PRM	CARM
1	REVENUE REQUIREMENT DEVELOPMENT						
2	FIXED COSTS						
3	BASE RESOURCES	$7,038,055	$6,232,021	$6,389,296	$19,659,373	$4,148,128	$2,241,168
4	OTHER EXISTING RESOURCES	2,141,647	1,896,375	1,944,233	5,982,255	1,262,256	681,977
5	ADDITIONAL ARM RESOURCES	0	0	2,839,729	2,839,729	2,748,858	90,871
6	SUB-TOTAL	$9,179,703	$8,128,396	$11,173,258	$28,481,356	$8,159,241	$3,014,017
7							
8	O&M						
9	BASE RESOURCES	$12,638,564	$11,191,130	$11,473,556	$35,303,250	$7,448,986	$4,024,571
10	OTHER EXISTING RESOURCES	2,660,026	2,355,386	2,414,828	7,430,239	1,567,780	847,047
11	ADDITIONAL ARM RESOURCES	0	0	253,422	253,422	156,816	96,606
12	SUB-TOTAL	$15,298,589	$13,546,516	$14,141,806	$42,986,911	$9,173,582	$4,968,224
13							
14	ENERGY						
15	BASE RESOURCES	$25,226,075	$23,835,642	$24,575,672	$73,637,389	$16,923,888	$7,135,531
16	OTHER EXISTING RESOURCES	6,237,567	7,259,986	8,011,534	21,509,087	7,939,980	587,806
17	ADDITIONAL ARM RESOURCES	0	0	234,910	234,910	227,393	7,517
18	SUB-TOTAL	$31,463,642	$31,095,628	$32,822,116	$95,381,386	$25,091,261	$7,730,854
19							
20	TOTAL RESOURCE COSTS						
21	BASE RESOURCES	$44,902,694	$41,258,794	$42,438,524	$128,600,012	$28,521,002	$13,401,270
22	OTHER EXISTING RESOURCES	11,039,240	11,511,746	12,370,594	34,921,581	10,770,016	2,116,830
23	ADDITIONAL ARM RESOURCES	0	0	3,328,061	3,328,061	3,133,066	194,995
24	SUB-TOTAL	$55,941,934	$52,770,540	$58,137,179	$166,849,654	$42,424,084	$15,713,095
25							
26							
27	RATE DEVELOPMENT						
28	BILLING DETERMINANTS						
29	BILLING DEMANDS	1,723,399	1,629,806	478,154	3,831,359	1,361,311	478,154
30	BASE RESOURCE KWH	784,700,545	738,282,902	759,805,654	2,282,789,101	522,616,908	226,109,971
31	OTHER EXISTING RESOURCES KWH	90,679,515	108,755,098	119,040,065	318,474,678	120,572,028	9,546,812
32	ADDITIONAL ARM RESOURCES KWH	0	0	3,200,000	3,200,000	3,097,600	102,400
33	TOTAL KWH	875,380,060	847,038,000	882,045,719	2,604,463,779	646,286,536	235,759,183
34							
35	MONTHLY CHARGES						
36	FIXED CHARGE	$764,975	$677,366	$931,105	$7.434	$679,937	$251,168
37	O&M CHARGE	$1,274,882	$1,128,876	$1,178,484	$11.220	$764,465	$414,019
38	BASE ENERGY CHARGE	$0.03215	$0.03229	$0.03234	$0.03226	$0.03238	$0.03156
39	OTHER EXISTING RESOURCE ENERGY CHARGE	$0.06879	$0.06676	$0.06746	$0.06754	$0.06604	$0.06170
40	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	$0.06746	$0.07341	$0.06604	$0.06170
41	AVERAGE ENERGY CHARGE	$0.035943	$0.036711	$0.037211	$0.036622	$0.038824	$0.032791

Arizona Electric Power Cooperative, Inc.

ASSIGNMENT OF BASE AND OTHER ENERGY RESOURCE COSTS AND CREDITS - Staff Adjusted

BASE RESOURCE ENERGY COSTS AND CREDITS

LINE NO.	DESCRIPTION	ENERGY	MEC	SSVEC	ARM	TRICO PRM	CARM
1	OPERATING EXPENSES:						
2	OPERATIONS						
3	COAL COSTS FOR TARIFF LOAD	$19,329,841	$6,678,640	$6,187,018	$6,464,183	$4,265,827	$1,845,608
4	COAL COSTS FOR RESOURCE TRANSFERS	1,145,169	398,862	269,962	476,345	303,180	525,914
5	COAL COSTS FOR THIRD PARTY SALES	2,507,121	1,199,603	705,665	601,853	420,098	181,755
6	RESOURCE TRANSFER CREDITS	(1,699,172)	(572,118)	(405,130)	(721,924)	(458,487)	(779,689)
7	SUB-TOTAL	$21,282,959	$7,704,987	$6,757,515	$6,820,457	$4,530,617	$1,773,588
8							
9	BASE COST BEFORE ADJUSTMENTS	56,603,695	19,457,317	18,306,352	18,840,027	13,150,478	5,689,548
10							
11	PRODUCTION - FUEL A/C 501	$77,886,654	$27,162,304	$25,063,867	$25,660,484	$17,681,095	$7,463,137
12							
13	ADJUSTMENTS						
14	PURCHASED POWER ACCOUNT 555 - ENERGY	1,701,090	584,744	550,154	566,192	395,206	170,986
15	TRANSMISSION OF ELEC BY OTHERS ACCOUNT 565 - ENERGY	2,880	990	932	959	669	290
16	FIRM CONTRACT REVENUES	(2,448,992)	(841,832)	(792,035)	(815,125)	(568,963)	(246,162)
17	BASE RESOURCE ECONOMY ENERGY	(3,504,243)	(1,680,130)	(987,275)	(836,838)	(584,119)	(252,719)
18	SCHEDULING REVENUES	0	0	0	0	0	0
19	OTHER OPERATING REVENUES	0	0	0	0	0	0
20	TOTAL NET BASE RESOURCES ENERGY REVENUE REQUIREMENTS	$73,637,389	$25,226,075	$23,835,642	$24,575,672	$16,923,888	$7,135,531
21							
22							

OTHER RESOURCE ENERGY COSTS AND CREDITS

23							
24	DESCRIPTION	ENERGY	MEC	SSVEC	ARM	TRICO	OTHER ARM
25	OTHER EXISTING RESOURCE COSTS	$21,509,087	$6,237,567	$7,259,986	$8,011,534	$7,939,980	$587,806
26	RESOURCE TRANSFER COSTS	1,699,172	272,834	749,346	676,992	1,143,573	49,671
27	OTHER RESOURCE COSTS	$19,809,915	$5,964,733	$6,510,640	$7,334,542	$6,796,407	$538,135
28							
29	RESOURCE TRANSFER KWH	35,966,376	5,616,722	15,907,156	14,442,498	25,707,138	1,158,264
30	OTHER RESOURCE KWH	282,508,302	85,062,793	92,847,942	104,597,567	94,864,890	8,388,548
31	TOTAL OTHER EXISTING RESOURCE KWH	318,474,678	90,679,515	108,755,098	119,040,065	120,572,028	9,546,812

Arizona Electric Power Cooperative, Inc.

DISTRIBUTION OF RATE BASE BY FUNCTION - Staff Adjusted

LINE NO.	DESCRIPTION	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES	TOTAL AEPCO
1					
2		THIS SCHEDULE IS NOT APPLICABLE			

Arizona Electric Power Cooperative, Inc.

Distribution of Expenses by Resource - Staff Adjusted (a)
(Reclassifications and Pro Forma Adjustments Included)

LINE NO.		TOTAL ADJUSTED O&M EXPENSES	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$77,906,029	$77,906,029	$0	$0
4	PRODUCTION - FUEL A/C 547	10,574,530	0	10,574,530	0
5	PRODUCTION - STEAM A/C 500	6,183,360	6,183,360	0	0
6	A/C 502	1,106,502	1,106,502	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	876,286	876,286	0	0
10	A/C 506 & 509	1,094,794	1,094,794	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	242,281	0	242,281	0
14	A/C 548	198,520	0	198,520	0
15	A/C 549	39,576	0	39,576	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY	0	0	0	0
18	- DEMAND A/C 555	3,117,006	751,678	0	2,365,328
19	- ENERGY A/C 555	13,428,376	1,701,090	11,492,376	234,910
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	2,539,437	2,225,793	310,523	3,120
22	A/C 557	0	0	0	0
23	TRANSMISSION		0	0	0
24	A/C 562	819	699	119	0
25	A/C 564	77	65	11	0
26	A/C 565	4,501,921	3,200,940	1,138,980	162,000
27	ADMINISTRATIVE & GENERAL	10,800,350	9,940,732	775,640	83,977
28	TOTAL OPERATIONS	$132,609,861	$104,987,969	$24,772,557	$2,849,335
29					
30	PRODUCTION - STEAM - A/C 510	$1,346,996	$1,346,996	$0	$0
31	A/C 511	27,649	27,649	0	0
32	A/C 512	4,018,147	4,018,147	0	0
33	A/C 513	5,638,224	5,638,224	0	0
34	A/C 514	2,390,050	2,390,050	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	52,802	0	52,802	0
37	A/C 552	3,190,952	0	3,190,952	0
38	A/C 553	1,746,819	0	1,746,819	0
39	A/C 554.	178,828	0	178,828	0
40	TRANSMISSION		0	0	0
41	A/C 570	13,900	11,874	2,026	0
42	GENERAL PLANT	355,096	325,750	25,022	4,325
43	TOTAL MAINTENANCE	$18,959,464	$13,758,690	$5,196,449	$4,325
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$8,317,632	$6,298,879	$1,993,016	$25,737
47	TAXES	2,933,343	2,617,177	316,166	0
48	TOTAL OTHER	$11,250,975	$8,916,056	$2,309,182	$25,737
49					
50	TOTAL OPERATING EXPENSES	$162,820,300	$127,662,715	$32,278,188	$2,879,397
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$10,812,194	$8,149,682	$2,653,298	$9,214
54	INT. CHARGES TO CONST.	(187,816)	(141,566)	(46,090)	(160)
55	OTHER INT. EXPENSE	1,047,090	847,554	193,845	5,690
56	OTHER DEDUCTIONS	151,174	113,947	37,098	129
57	TOTAL INT. & OTHER DED.	$11,822,642	$8,969,617	$2,838,151	$14,873
58					
59	TOTAL EXPENSES	$ 174,642,942	$ 136,632,333	$ 35,116,339	$ 2,894,270
60					
61					
62					
63	SUPPORTING SCHEDULES:				
64	(a) Sum of DMK Schedules G-6, PAGES 2, 3, 3.1 (Staff Adjustments) AND 4				
65					

Arizona Electric Power Cooperative, Inc.

Distribution of Booked Expenses by Resource - See Staff Note Below*

LINE NO.		TOTAL BOOKED O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$61,965,748	$61,965,748	$0	$0
4	PRODUCTION - FUEL A/C 547	10,574,530	0	10,574,530	0
5	PRODUCTION - STEAM A/C 500	5,997,229	5,997,229	0	0
6	A/C 502	2,795,766	2,795,766	0	0
7	A/C 503	0		0	0
8	A/C 504	0		0	0
9	A/C 505	1,385,698	1,385,698	0	0
10	A/C 506 & 509	1,083,857	1,083,857	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	234,983	0	234,983	0
14	A/C 548	707,145	0	707,145	0
15	A/C 549	39,148	0	39,148	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	6,274,506	751,678	2,925,000	2,597,828
19	- ENERGY A/C 555	35,795,431	1,701,090	30,545,119	3,549,222
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	3,315,542	2,906,043	405,426	4,074
22	A/C 557	1,548,021	1,356,826	189,293	1,902
23	TRANSMISSION				
24	A/C 562	819	699	119	0
25	A/C 564	77	65	11	0
26	A/C 565	16,345,082	14,201,775	1,981,307	162,000
27	ADMINISTRATIVE & GENERAL	11,249,966	10,299,504	791,139	159,323
28	TOTAL OPERATIONS	$159,313,546	$104,445,978	$48,393,220	$6,474,348
29					
30	PRODUCTION - STEAM - A/C 510	$1,302,263	$1,302,263	$0	$0
31	A/C 511	26,944	26,944	0	0
32	A/C 512	4,763,936	4,763,936	0	0
33	A/C 513	6,184,656	6,184,656	0	0
34	A/C 514	2,334,541	2,334,541	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	51,049	0	51,049	0
37	A/C 552	27,641	0	27,641	0
38	A/C 553	1,384,550	0	1,384,550	0
39	A/C 554.	175,654	0	175,654	0
40	TRANSMISSION				
41	A/C 570	13,624	11,638	1,986	0
42	GENERAL PLANT	304,878	279,120	21,440	4,318
43	TOTAL MAINTENANCE	$16,569,736	$14,903,098	$1,662,320	$4,318
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$7,883,883	$5,904,356	$1,960,365	$19,162
47	TAXES	0	0	0	0
48	TOTAL OTHER	$7,883,883	$5,904,356	$1,960,365	$19,162
49					
50	TOTAL OPERATING EXPENSES	$183,767,165	$125,253,432	$52,015,905	$6,497,828
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$10,580,757	$7,975,236	$2,596,504	$9,017
54	INT. CHARGES TO CONST.	(187,816)	(141,566)	(46,090)	(160)
55	OTHER INT. EXPENSE	781,804	589,284	191,854	666
56	OTHER DEDUCTIONS	151,174	113,947	37,098	129
57	TOTAL INT. & OTHER DED.	$11,325,919	$8,536,901	$2,779,365	$9,652
58					
59	TOTAL EXPENSES	$ 195,093,084	$ 133,790,334	$ 54,795,271	$ 6,507,480
60					
61	* STAFF NOTE - This Schedule is the same as filed by AEPCO				
62					
63	SUPPORTING SCHEDULES:				
64	(a) C-1, PAGES 1 AND 2				
65	(b) C-1, PAGE 2, LINES 44 + 50				

Arizona Electric Power Cooperative, Inc.

Distribution of Pro-Forma Adjustments by Resource - See Staff Note Below*

LINE NO.		ADJUSTMENTS TO O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$16,520,095	$16,520,095	$0	$0
4	PRODUCTION - FUEL A/C 547	0	0	0	0
5	PRODUCTION - STEAM A/C 500	354,307	354,307	0	0
6	A/C 502	35,855	35,855	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	0	0	0	0
10	A/C 506 & 509	20,818	20,818	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	13,891	0	13,891	0
14	A/C 548	1,405	0	1,405	0
15	A/C 549	816	0	816	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	(3,157,500)	0	(2,925,000)	(232,500)
19	- ENERGY A/C 555	(22,367,055)	0	(19,052,743)	(3,314,312)
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	109,150	95,669	13,347	134
22	A/C 557	0	0	0	0
23	TRANSMISSION				
24	A/C 562	0	0	0	0
25	A/C 564	0	0	0	0
26	A/C 565	(4,963,137)	(4,963,137)	0	0
27	ADMINISTRATIVE & GENERAL	540,635	477,180	60,665	2,790
28	TOTAL OPERATIONS	($12,890,718)	$12,540,789	($21,887,619)	($3,543,888)
29					
30	PRODUCTION - STEAM - A/C 510	$85,151	$85,151	$0	$0
31	A/C 511	1,342	1,342	0	0
32	A/C 512	(680,227)	(680,227)	0	0
33	A/C 513	(533,229)	(533,229)	0	0
34	A/C 514	105,663	105,663	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	3,337	0	3,337	0
37	A/C 552	3,164,043	0	3,164,043	0
38	A/C 553	376,795	0	376,795	0
39	A/C 554.	6,042	0	6,042	0
40	TRANSMISSION				
41	A/C 570	526	449	77	0
42	GENERAL PLANT	95,593	88,761	6,818	14
43	TOTAL MAINTENANCE	$2,625,037	($932,089)	$3,557,112	$14
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$464,285	$425,060	$32,650	$6,575
47	TAXES	0	0	0	0
48	TOTAL OTHER	$464,285	$425,060	$32,650	$6,575
49					
50	TOTAL OPERATING EXPENSES	($9,801,397)	$12,033,759	($18,297,857)	($3,537,299)
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$231,437	$174,445	$56,794	$197
54	INT. CHARGES TO CONST.	0	0	0	0
55	OTHER INT. EXPENSE	360,470	330,015	25,350	5,105
56	OTHER DEDUCTIONS	0	0	0	0
57	TOTAL INT. & OTHER DED.	$591,907	$504,461	$82,144	$5,302
58					
59	TOTAL EXPENSES	($9,209,490)	$12,538,220	($18,215,713)	($3,531,996)
60					

61 * STAFF NOTE - This Schedule is the same as filed by AEPCO

62

63 SUPPORTING SCHEDULES:

64 (a) C-1, PAGES 3 & 4

65 (b) C-1, PAGE 4, LINES 44 + 50

Arizona Electric Power Cooperative, Inc.

Distribution of Pro-Forma Adjustments by Resource - Staff Proposed Expense Adjustments

LINE NO.		ADJUSTMENTS TO O&M EXPENSES (a)	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	$ (28,439)	$ (28,439)	$ -	$ -
4	PRODUCTION - FUEL A/C 547	-	-	-	-
5	PRODUCTION - STEAM A/C 500	(168,177)	(168,177)	-	-
6	A/C 502	(17,019)	(17,019)	-	-
7	A/C 503	-	-	-	-
8	A/C 504	-	-	-	-
9	A/C 505	(0)	(0)	-	-
10	A/C 506 & 509	(9,882)	(9,882)	-	-
11	A/C 507	-	-	-	-
12	A/C 508	-	-	-	-
13	PRODUCTION - OTHER - A/C 546	(6,594)	-	(6,594)	-
14	A/C 548	(667)	-	(667)	-
15	A/C 549	(387)	-	(387)	-
16	A/C 550	-	-	-	-
17	OTHER POWER SUPPLY		-	-	-
18	- DEMAND A/C 555	-	-	-	-
19	- ENERGY A/C 555	-	-	-	-
20	- INDIRECT A/C 555	-	-	-	-
21	A/C 556	(51,810)	(45,411)	(6,335)	(64)
22	A/C 557	-	-	-	-
23	TRANSMISSION		-	-	-
24	A/C 562	-	-	-	-
25	A/C 564	-	-	-	-
26	A/C 565	-	-	-	-
27	ADMINISTRATIVE & GENERAL	(1,254,542)	(1,077,913)	(94,750)	(81,879)
28	TOTAL OPERATIONS	$ (1,537,517)	$ (1,346,841)	$ (108,733)	$ (81,943)
29					
30	PRODUCTION - STEAM - A/C 510	$ (40,418)	$ (40,418)	$ -	$ -
31	A/C 511	(637)	(637)	-	-
32	A/C 512	(65,562)	(65,562)	-	-
33	A/C 513	(13,203)	(13,203)	-	-
34	A/C 514	(50,155)	(50,155)	-	-
35	A/C 515.	-	-	-	-
36	PRODUCTION - OTHER - A/C 551	(1,584)	-	(1,584)	-
37	A/C 552	(732)	-	(732)	-
38	A/C 553	(14,526)	-	(14,526)	-
39	A/C 554.	(2,868)	-	(2,868)	-
40	TRANSMISSION		-	-	-
41	A/C 570	(250)	(213)	(36)	-
42	GENERAL PLANT	(45,374)	(42,132)	(3,236)	(6)
43	TOTAL MAINTENANCE	$ (235,309)	$ (212,319)	$ (22,983)	$ (6)
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$ (30,536)	$ (30,536)		
47	TAXES	-			
48	TOTAL OTHER	$ (30,536)	$ (30,536)	$ -	$ -
49					
50	TOTAL OPERATING EXPENSES	$ (1,803,362)	$ (1,589,697)	$ (131,716)	$ (81,949)
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$ -			
54	INT. CHARGES TO CONST.	-			
55	OTHER INT. EXPENSE	(95,184)	(71,745)	(23,358)	(81)
56	OTHER DEDUCTIONS	-			
57	TOTAL INT. & OTHER DED.	$ (95,184)	$ (71,745)	$ (23,358)	$ (81)
58					
59	TOTAL EXPENSES	$ (1,898,546)	$ (1,661,442)	$ (155,074)	$ (82,030)
60					
61					
62					
63	SUPPORTING SCHEDULES:				
64	(a) DMK Sch. G-6 PAGES 3.2 & 3.3				
65					

Arizona Electric Power Cooperative, Inc.

Distribution of Staff Payroll and Benefit Adjustment to O&M Expense Accounts

		AEPCO Distribution of Adjusted Payroll by Resource				Dist. of Staff Payroll/Benefits/Incentive C-1 Adj. by Resource			
Line	Account Description	Adjusted Payroll	Base	Other Existing Resources	Additional ARM Resources	Adjustments Payroll	Base	Other Existing Resources	Additional ARM Resources
1	OPERATING EXPENSES:								
2	OPERATIONS								
3	PRODUCTION - FUEL A/C 501	$769,808	$769,808	$0	$0	($28,439)	($28,439)	$0	$0
4	PRODUCTION - FUEL A/C 547	0	0	0	0	0	0	0	0
5	PRODUCTION - STEAM A/C 500	4,552,260	4,552,260	0	0	(168,177)	(168,177)	0	0
6	A/C 502	460,682	460,682	0	0	(17,019)	(17,019)	0	0
7	A/C 503					0	0	0	0
8	A/C 504					0	0	0	0
9	A/C 505	0	0	0	0	(0)	(0)	0	0
10	A/C 506 & 509	267,481	267,481	0	0	(9,882)	(9,882)	0	0
11	A/C 507					0	0	0	0
12	A/C 508					0	0	0	0
13	PRODUCTION - OTHER - A/C 546	178,481	0	178,481	0	(6,594)	0	(6,594)	0
14	A/C 548	18,048	0	18,048	0	(667)	0	(667)	0
15	A/C 549	10,479	0	10,479	0	(387)	0	(387)	0
16	A/C 550					0	0	0	0
17	OTHER POWER SUPPLY					0	0	0	0
18	- DEMAND A/C 555	0	0	0	0	0	0	0	0
19	- ENERGY A/C 555	0	0	0	0	0	0	0	0
20	- INDIRECT A/C 555	0	0	0	0	0	0	0	0
21	A/C 556	1,402,401	1,229,192	171,486	1,723	(51,810)	(45,411)	(6,335)	(64)
22	A/C 557	0	0	0	0	0	0	0	0
23	TRANSMISSION	0	0	0	0	0	0	0	0
24	A/C 562	0	0	0	0	0	0	0	0
25	A/C 564	0	0	0	0	0	0	0	0
26	A/C 565	0	0	0	0	0	0	0	0
27	ADMINISTRATIVE & GENERAL	10,298,856	9,562,837	734,554	1,465	(380,476)	(353,285)	(27,137)	(54)
28	TOTAL OPERATIONS	$17,958,496	$16,842,260	$1,113,048	$3,188	($663,451)	($622,213)	($41,120)	($118)
29						0	0	0	0
30	PRODUCTION - STEAM - A/C 510	1,094,051	1,094,051	0	0	(40,418)	(40,418)	0	0
31	A/C 511	17,237	17,237	0	0	(637)	(637)	0	0
32	A/C 512	1,774,656	1,774,656	0	0	(65,562)	(65,562)	0	0
33	A/C 513	357,375	357,375	0	0	(13,203)	(13,203)	0	0
34	A/C 514	1,357,599	1,357,599	0	0	(50,155)	(50,155)	0	0
35	A/C 515.					0	0	0	0
36	PRODUCTION - OTHER - A/C 551	42,879	0	42,879	0	(1,584)	0	(1,584)	0
37	A/C 552	19,823	0	19,823	0	(732)	0	(732)	0
38	A/C 553	393,202	0	393,202	0	(14,526)	0	(14,526)	0
39	A/C 554.	77,630	0	77,630	0	(2,868)	0	(2,868)	0
40	TRANSMISSION					0	0	0	0
41	A/C 570	6,757	5,772	985	0	(250)	(213)	(36)	0
42	GENERAL PLANT	1,228,209	1,140,434	87,601	175	(45,374)	(42,132)	(3,236)	(6)
43	TOTAL MAINTENANCE	$6,369,418	$5,747,125	$622,119	$175	($235,309)	($212,319)	($22,983)	($6)
44									
45	TOTAL LABOR	$24,327,914	$22,589,385	$1,735,167	$3,362	($898,760)	($834,533)	($64,103)	($124)
46									
47	PAYROLL ALLOCATOR 1	100.000%	92.853%	7.132%	0.014%	($898,760) Staff C-1 Adj. Net Decrease In Labor Expenses			
48	PAYROLL ALLOCATOR 2	5.049%	4.688%	0.360%		Allocated based upon ratio of As-filed account $/Total Labor$			
		100.000%	92.854%	7.132%	0.014%				
		100.000%	92.867%	7.133%					

Arizona Electric Power Cooperative, Inc.

Distribution of Pro-Forma Adjustments by Resource - Staff Adjustments

Staff Adj.	Description	Staff Alloc. Factor Ref.	Dist. of Staff Adjustments by Resource: Staff Adjustments	Base	Other Existing Resources	Additional ARM Resources	Proof
C-1	Var. Accts. Payroll Related Adjustments	See G-6,p3.2, L45	$ (898,760)	$ (834,533)	$ (64,103)	$ (124)	(0)
C-2	A&G - Removal of Incentive Compensation	A-2	$ (681,900)	$ (565,316)	$ (52,748)	$ (63,836)	0
C-3	A&G - Removal of Donations Expenses	A-2	$ (79,926)	$ (66,261)	$ (6,183)	$ (7,482)	0
C-4	A&G - Removal of Lobbying Expenses	A-2	$ (112,240)	$ (93,051)	$ (8,682)	$ (10,507)	0
C-5a	Depr. - ST2 & ST3 Reduction In Depr. Exp.	A-3	$ (30,536)	$ (30,536)	$ -	$ -	0
C-5b	Other. Int. Exp - Reductrion In Accretion Exp.	A-4	$ (95,184)	$ (71,745)	$ (23,358)	$ (81)	0
	Total Staff Expense Adjustments		$ (1,898,546)	$ (1,661,442)	$ (155,074)	$ (82,030)	(0)
	Development of Staff Allocation Factors						
	Total Admin & General	AEPCO G-6,p1,L27	$ 12,054,892	$ 11,018,645	$ 870,391	$ 165,856	0
	Payroll Expenses	See G-6,p3.2,L27	10,298,856	9,562,837	734,554	1,465	0
	A&G Net Of Payroll		$ 1,756,036	$ 1,455,808	$ 135,837	$ 164,391	0
	Staff Allocation Factor	A-2	100%	82.90%	7.74%	9.36%	0
	ST2 & ST3 Depr. Direct Staff Alloc. Factor	A-3	100%	100.00%	0.00%	0.00%	0
	Int. On Long Term Debt -AEPCO G-6,p2 L53	AEPCO G-6,p2,L53	$10,580,757	$7,975,236	$2,596,504	$9,017	0
	Staff Allocation Factor	A-4	100%	75.37%	24.54%	0.09%	(0)

Arizona Electric Power Cooperative, Inc.

Distribution of Expense Reclassifications by Resource - See Staff Note Below*

LINE NO.		RECLASSIFICATIONS OF O&M EXPENSES	BASE	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES
1	OPERATING EXPENSES:				
2	OPERATIONS				
3	PRODUCTION - FUEL A/C 501	($551,375)	(551,375)	$0	$0
4	PRODUCTION - FUEL A/C 547	0	0	0	0
5	PRODUCTION - STEAM A/C 500	0	0	0	0
6	A/C 502	(1,708,100)	(1,708,100)	0	0
7	A/C 503	0	0	0	0
8	A/C 504	0	0	0	0
9	A/C 505	(509,412)	(509,412)	0	0
10	A/C 506 & 509	0	0	0	0
11	A/C 507	0	0	0	0
12	A/C 508	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	0	0	0	0
14	A/C 548	(509,363)	0	(509,363)	0
15	A/C 549	0	0	0	0
16	A/C 550	0	0	0	0
17	OTHER POWER SUPPLY				
18	- DEMAND A/C 555	0	0		
19	- ENERGY A/C 555	0	0	0	0
20	- INDIRECT A/C 555	0	0	0	0
21	A/C 556	(833,446)	(730,508)	(101,914)	(1,024)
22	A/C 557	(1,548,021)	(1356826)	(189293)	(1902)
23	TRANSMISSION				
24	A/C 562	0	0	0	0
25	A/C 564	0	0	0	0
26	A/C 565	(6,880,024)	(6,037,697)	(842,327)	0
27	ADMINISTRATIVE & GENERAL	264,291	241,962	18,586	3,743
28	TOTAL OPERATIONS	($12,275,450)	($10,651,957)	($1,624,310)	$817
29					
30	PRODUCTION - STEAM - A/C 510	$0	$0	$0	$0
31	A/C 511	0	0	0	0
32	A/C 512	0	0	0	0
33	A/C 513	0	0	0	0
34	A/C 514	0	0	0	0
35	A/C 515.	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	0	0	0	0
37	A/C 552	0	0	0	0
38	A/C 553	0	0	0	0
39	A/C 554.	0	0	0	0
40	TRANSMISSION				
41	A/C 570	0	0	0	0
42	GENERAL PLANT	0	0	0	0
43	TOTAL MAINTENANCE	$0	$0	$0	$0
44					
45	OTHER:				
46	DEPRECIATION & AMORTIZATION	$0	$0	$0	$0
47	TAXES	2,933,343	2,617,177	316,166	0
48	TOTAL OTHER	$2,933,343	$2,617,177	$316,166	$0
49					
50	TOTAL OPERATING EXPENSES	($9,342,107)	($8,034,780)	($1,308,144)	$817
51					
52	INT. & OTHER DEDUCTIONS:				
53	INT. ON LONG-TERM DEBT	$0	$0	$0	$0
54	INT. CHARGES TO CONST.	0	0	0	0
55	OTHER INT. EXPENSE	0	0	0	0
56	OTHER DEDUCTIONS	0	0	0	0
57	TOTAL INT. & OTHER DED.	$0	$0	$0	$0
58					
59	TOTAL EXPENSES	($9,342,107)	($8,034,780)	($1,308,144)	$817
60					
61	* STAFF NOTE - This Schedule is the same as filed by AEPCO				
62					
63	SUPPORTING SCHEDULES:				
64	(a) C-2, PAGES 1 & 2				
65	(b) C-2, PAGE 2, LINES 44 + 50				

Arizona Electric Power Cooperative, Inc.

Class A Member Revenue Requirements by Function - Staff Adjusted

LINE NO.		BASE RESOURCES			OTHER EXISTING RESOURCES			ADDITIONAL ARM RESOURCES			TOTAL AEPCO REVENUE REQUIREMENT			
		FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	FIXED	O&M	ENERGY	Total
1	OPERATING EXPENSES:													
2	OPERATIONS													
3	PRODUCTION - FUEL A/C 501	$19,375	$0	$77,886,654	$0	$0	$0	$0	$0	$0	$19,375	$0	$77,886,654	$77,906,029
4	PRODUCTION - FUEL A/C 547	0	0	0	109,790	0	10,464,740	0	0	0	109,790	0	10,464,740	10,574,530
5	PRODUCTION - STEAM A/C 500	0	6,183,360	0	0	0	0	0	0	0	0	6,183,360	0	6,183,360
6	A/C 502	1,123,521	(17,019)	0	0	0	0	0	0	0	1,123,521	(17,019)	0	1,106,502
7	A/C 503	0	0	0	0	0	0	0	0	0	0	0	0	0
8	A/C 504	0	0	0	0	0	0	0	0	0	0	0	0	0
9	A/C 505	92,400	783,886	0	0	0	0	0	0	0	92,400	783,886	0	876,286
10	A/C 506 & 509	0	1,094,794	0	0	0	0	0	0	0	0	1,094,794	0	1,094,794
11	A/C 507	0	0	0	0	0	0	0	0	0	0	0	0	0
12	A/C 508	0	0	0	0	0	0	0	0	0	0	0	0	0
13	PRODUCTION - OTHER - A/C 546	0	0	0	0	242,281	0	0	0	0	0	242,281	0	242,281
14	A/C 548	0	0	0	79,166	119,354	0	0	0	0	79,166	119,354	0	198,520
15	A/C 549	0	0	0	0	39,576	0	0	0	0	0	39,576	0	39,576
16	A/C 550	0	0	0	0	0	0	0	0	0	0	0	0	0
17	OTHER POWER SUPPLY													
18	- DEMAND A/C 555	751,678	0	0	0	0	0	2,365,328	0	0	3,117,006	0	0	3,117,006
19	- ENERGY A/C 555	0		1,701,090	0	0	11,492,376	0	0	234,910	0	0	13,428,376	13,428,376
20	- INDIRECT A/C 555	0	0	0	0	0	0	0	0	0	0	0	0	0
21	A/C 556	0	2,225,793	0	0	310,523	0	0	3,120	0	0	2,539,437	0	2,539,437
22	A/C 557	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TRANSMISSION													
24	A/C 562	0	699	0	0	119	0	0	0	0	0	819	0	819
25	A/C 564	0	65	0	0	11	0	0	0	0	0	77	0	77
26	A/C 565	0	3,198,060	2,880	0	1,138,980	0	0	162,000	0	0	4,499,040	2,880	4,501,921
27	ADMINISTRATIVE & GENERAL	0	9,940,732	0		775,640	0	0	83,977	0	0	10,800,350	0	10,800,350
28	TOTAL OPERATIONS	$1,986,974	$23,410,371	$79,590,624	$188,956	$2,626,485	$21,957,116	$2,365,328	$249,097	$234,910	$4,541,257	$26,285,954	$101,782,650	$132,609,861
29														
30	PRODUCTION - STEAM - A/C 510	0	1,346,996	0	0	0	0	0	0	0	0	1,346,996	0	1,346,996
31	A/C 511	0	27,649	0	0	0	0	0	0	0	0	27,649	0	27,649
32	A/C 512	0	4,018,147	0	0	0	0	0	0	0	0	4,018,147	0	4,018,147
33	A/C 513	0	5,638,224	0	0	0	0	0	0	0	0	5,638,224	0	5,638,224
34	A/C 514	0	2,390,050	0	0	0	0	0	0	0	0	2,390,050	0	2,390,050
35	A/C 515.	0	0	0	0	0	0	0	0	0	0	0	0	0
36	PRODUCTION - OTHER - A/C 551	0	0	0	0	52,802	0	0	0	0	0	52,802	0	52,802
37	A/C 552	0	0	0	0	3,190,952	0	0	0	0	0	3,190,952	0	3,190,952
38	A/C 553	0	0	0	0	1,746,819	0	0	0	0	0	1,746,819	0	1,746,819
39	A/C 554.	0	0	0	0	178,828	0	0	0	0	0	178,828	0	178,828
40	TRANSMISSION													
41	A/C 570	0	11,874	0	0	2,026	0	0	0	0	0	13,900	0	13,900
42	GENERAL PLANT	0	325,750	0	0	25,022	0	0	4,325	0	0	355,096	0	355,096
43	TOTAL MAINTENANCE	$0	$13,758,690	$0	$0	$5,196,449	$0	$0	$4,325	$0	$0	$18,959,464	$0	$18,959,464
44														
45	OTHER:													
46	DEPRECIATION & AMORTIZATION	$6,298,879	$0	$0	$1,993,016	$0	$0	$25,737	$0	$0	8,317,632	0	0	8,317,632
47	TAXES	2,617,177	0	0	316,166	0	0	0	0	0	2,933,343	0	0	2,933,343
48	TOTAL OTHER	$8,916,056	$0	$0	$2,309,182	$0	$0	$25,737	$0	$0	$11,250,975	$0	$0	$11,250,975
49														
50	TOTAL OPERATING EXPENSES	$10,903,030	$37,169,061	$79,590,624	$2,498,138	$7,822,934	$21,957,116	$2,391,065	$253,422	$234,910	$15,792,232	$45,245,417	$101,782,650	$162,820,300
51														
52	INT. & OTHER DEDUCTIONS:													
53	INT. ON LONG-TERM DEBT	$8,149,682	$0	$0	$2,653,298	$0	$0	$9,214	$0	$0	$10,812,194	$0	$0	$10,812,194
54	INT. CHARGES TO CONST.	(141,566)	0	0	(46,090)	0	0	(160)	0	0	(187,816)	0	0	(187,816)
55	OTHER INT. EXPENSE	847,554	0	0	193,845	0	0	5,690	0	0	1,047,090	0	0	1,047,090
56	OTHER DEDUCTIONS	113,947	0	0	37,098	0	0	129	0	0	151,174	0	0	151,174
57	TOTAL INT. & OTHER DED.	$8,969,617	$0	$0	$2,838,151	$0	$0	$14,873	$0	$0	$11,822,642	$0	$0	$11,822,642
58														
59	TOTAL EXPENSES	$19,872,647	$37,169,061	$79,590,624	$5,336,289	$7,822,934	$21,957,116	$2,405,938	$253,422	$234,910	$27,614,874	$45,245,417	$101,782,650	$174,642,942
60														
61	REVENUE CREDITS													
62	FIRM CONTRACT REVENUES	$1,430,539	$0	$2,448,992	$0	$0	$0	$0	$0	$0	$1,430,539	$0	$2,448,992	$3,879,531
63	ECONOMY ENERGY	0	0	3,504,243	0	0	448,029	0	0	0	0	0	3,952,272	3,952,272
64	SCHEDULING REVENUES (all to ARMs)	788,294	0	0	0	0	0	0	0	0	788,294	0	0	788,294
65	OTHER OPERATING REVENUES	997,566	1,865,811	0	267,871	392,695	0	0	0	0	1,265,437	2,258,506	0	3,523,943
66	TOTAL REVENUE CREDITS	$3,216,399	$1,865,811	$5,953,235	$267,871	$392,695	$448,029	$0	$0	$0	$3,484,270	$2,258,506	$6,401,264	$12,144,040
67														
68	MARGINS	3,003,124	0	0	913,837	0	0	433,791	0	0	4,350,752	0	0	4,350,752
69														
70	CLASS A MEMBER REVENUE REQUIREMENTS	$ 19,659,373	$ 35,303,250	$ 73,637,389	$ 5,982,255	$ 7,430,239	$ 21,509,087	$ 2,839,729	$253,422	$ 234,910	$28,481,356	$42,986,911	$ 95,381,386	$ 166,849,654

Arizona Electric Power Cooperative, Inc.

DERIVATION OF ALLOCATION FACTORS - Staff Adjusted

LINE NO.	DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TOTAL AEPCO	TRICO PRM	CARMs
1	ALLOCATION FACTORS						
2	ENERGY ALLOCATION FACTORS						
3	BASE RESOURCE KWH	784,700,545	738,282,902	759,805,654	2,282,789,101	522,616,908	226,109,971
4	OTHER EXISTING RESOURCES KWH	90,679,515	108,755,098	119,040,065	318,474,678	120,572,028	9,546,812
5	ADDITIONAL ARM RESOURCES KWH	0	0	3,200,000	3,200,000	3,097,600	102,400
6							
7	BASE RESOURCE KWH	34.375%	32.341%	33.284%	100.000%	22.894%	9.905%
8	OTHER EXISTING RESOURCES KWH	28.473%	34.149%	37.378%	100.000%	37.859%	2.998%
9	ADDITIONAL ARM RESOURCES KWH	0.000%	0.000%	100.000%	100.000%	96.800%	3.200%
10							
11	FIXED COST ALLOCATION FACTORS						
12	ACP	35.800%	31.700%	32.500%	100.000%	21.100%	11.400%
13	ACP OF SOUTH POINT & GRIFFITH	0.000%	0.000%	100.000%	100.000%	96.800%	3.200%
14							

15	FUNCTIONALIZATION FACTORS	BASE RESOURCES	OTHER EXISTING RESOURCES	ADDITIONAL ARM RESOURCES	TOTAL AEPC
16	DISPATCHED ENERGY (KWH)	2,282,789,101	318,474,678	3,200,000	2,604,463,779
17	DISPATCHED ENERGY (%)	87.649%	12.228%	0.123%	100.000%
18					
19	SUB-TOTAL PURCHASED POWER				
20	PRODUCTION - FUEL A/C 501	$61,965,748	$0	$0	$61,965,748
21	PRODUCTION - FUEL A/C 547	0	10,574,530	0	10574530.1
22	SUBTOTAL ($)	$61,965,748	$10,574,530	$0	$72,540,278
23	SUBTOTAL (%)	85.423%	14.577%	0.000%	100.000%
24					
25	PAYROLL EXCLUDING A&G AND GEN PLT MNTC ($)	$10,961,004	$841,952	$1,589	$11,804,545
26	PAYROLL EXCLUDING A&G AND GEN PLT MNTC (%)	92.854%	7.132%	0.013%	100.000%
27					
28	INTEREST ON LONG TERM DEBT ($)	$7,975,236	$2,596,504	$9,017	$10,580,757
29	INTEREST ON LONG TERM DEBT (%)	75.375%	24.540%	0.085%	100.000%
30					
31	TOTAL EXPENSES LESS A&G ($)	$126,691,600	$34,340,699	$2,810,293	$163,842,592
32	TOTAL EXPENSES LESS A&G (%)	77.325%	20.960%	1.715%	100.000%
33					
34	A&G EXPENSES ($)	$10,299,504	$791,139	$159,323	$11,249,966
35	A&G EXPENSES (%)	91.551%	7.032%	1.416%	100.000%

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class - Staff Adjusted
March 31, 2009 Adjusted Test Year

Line			AEPCO REBUTTAL			STAFF DIRECT AND SURREBUTTAL		
No.	CLASS OF SERVICE	PRESENT	PROPOSED	INCREASE	PERCENT	PROPOSED	INCREASE	PERCENT
1	Total Class A Member Revenues	$166,618,638	$165,446,321	($1,172,317)	-0.70%	$166,849,654	$231,015	0.14%
2	Non-Members	8,620,097	8,620,097	0	0.00%	8,620,097	0	0.00%
3	Other Operating Revenues	3,523,943	3,523,943	0	0.00%	3,523,943	0	0.00%
4	Total AEPCO	$178,762,678	$177,590,361	($1,172,317)	($0)	$178,993,694	$231,015	0.13%

Note: Revenues stated using synchronized FPPCA.

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class - Staff Adjusted
March 31, 2009 Adjusted Test Year

Line No.	CLASS OF SERVICE	CUSTOMERS	KWH CONSUMPTION	BILLING KW	REVENUE PRESENT	REVENUE PROPOSED	PROPOSED INCREASE ($)	PROPOSED INCREASE (%)
1	Member Contracts:							
2	Anza	1	51,283,408	96,412	$3,353,127	$3,290,011	($63,117)	-1.88%
3	Duncan	1	28,079,760	57,180	1,901,744	1,875,847	(25,897)	-1.36%
4	Graham	1	156,396,015	324,562	10,683,325	10,547,237	(136,087)	-1.27%
5	Mohave	1	875,380,060	1,723,399	54,205,506	55,941,934	1,736,428	3.20%
6	Sulphur	1	847,038,000	1,629,806	52,026,365	52,770,540	744,175	1.43%
7	Trico	1	646,286,536	1,361,311	44,448,572	42,424,084	(2,024,487)	-4.55%
8	Total Class A Members	6	2,604,463,779	5,192,670	$166,618,638	$166,849,654	$231,015	0.14%
9								
10	Other Firm Contracts:							
11	City of Mesa	0	0	0	$0	$0	N/A	N/A
12	Salt River Project	0	0	0	0	0	N/A	N/A
13	Public Service Company of New Mexico	0	0	0	0	0	N/A	N/A
14	ED2	1	68,952,281	96,000	3,879,531	3,879,531	$0	0.00%
15	Total Firm Contracts	1	68,952,281	96,000	$3,879,531	$3,879,531	$0	0.00%
16								
17	Total AEPCO	7	2,673,416,060	5,288,670	$170,498,169	$170,729,184	$231,015	0.14%

Note: Revenues stated using synchronized FPPCA.

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER BOOKED SALES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	ANZA													
2	MW	5.712	7.488	10.608	10.404	9.948	9.684	6.852	5.388	8.860	8.093	7.071	6.304	96.412
3	MWH	3,733.956	3,974.280	4,547.868	5,266.380	5,087.034	4,309.788	3,861.588	3,682.884	4,682.804	4,126.590	3,963.021	4,047.215	51,283.408
4														
5	DUNCAN													
6	MW	3.860	6.040	6.960	5.940	6.620	5.360	4.020	2.780	4.300	3.900	3.900	3.500	57.180
7	MWH	2,004.660	2,422.840	3,223.350	2,960.420	2,955.880	2,300.600	1,919.560	1,905.850	2,292.120	2,226.640	1,883.390	1,984.450	28,079.760
8														
9	GRAHAM													
10	MW	20.966	31.511	39.951	39.726	36.986	32.263	24.988	18.448	20.642	19.992	18.818	20.271	324.562
11	MWH	10,775.112	12,244.130	18,499.166	17,976.098	17,655.323	13,801.595	11,076.763	10,334.556	12,000.020	11,134.378	9,221.331	11,677.543	156,396.015
12														
13	MOHAVE													
14	MW	95.000	103.000	110.000	132.000	133.000	124.000	102.000	72.000	79.000	79.000	76.000	54.000	1,158.000
15	MWH	62,986.000	66,854.000	69,860.000	77,273.000	77,009.000	68,313.000	58,371.000	45,187.000	48,485.000	46,549.000	40,805.000	39,120.000	700,812.000
16														
17	SULPHUR													
18	MW	84.000	88.000	102.000	96.000	97.000	100.000	89.000	77.000	97.000	97.000	104.000	91.000	1,122.000
19	MWH	56,633.000	61,631.000	61,830.000	61,828.000	62,148.000	59,310.000	55,640.000	48,978.000	56,895.000	57,703.000	53,357.000	56,528.000	692,481.000
20														
21	TRICO													
22	MW	85.694	125.853	164.497	149.759	155.557	140.957	116.234	91.507	90.195	85.104	80.967	72.836	1,359.160
23	MWH	43,348.839	49,883.272	69,143.826	72,230.849	72,594.073	62,002.723	50,728.275	42,934.549	49,950.664	48,018.911	41,759.997	43,690.558	646,286.536
24														
25														
26														
27	FULL REQUIREMENTS													
28	MW	30.538	45.039	57.519	56.070	53.554	47.307	35.860	26.616	33.802	31.985	29.789	30.075	478.154
29	MWH	16,513.728	18,641.250	26,270.384	26,202.898	25,698.237	20,411.983	16,857.911	15,923.290	18,974.944	17,487.608	15,067.742	17,709.208	235,759.183
30														
31	PARTIAL REQUIREMENTS													
32	MW	264.694	316.853	376.497	377.759	385.557	364.957	307.234	240.507	266.195	261.104	259.967	217.836	3,639.160
33	MWH	162,967.839	178,368.272	200,833.826	211,331.849	211,751.073	189,625.723	164,739.275	137,099.549	155,330.664	152,270.911	135,921.997	139,338.558	2,039,579.536
34														
35														
36														
37	TOTAL CLASS A													
38	MW	295.232	361.892	434.016	433.829	439.111	412.264	343.094	267.123	299.997	293.089	289.756	247.911	4,117.314
39	MWH	179,481.567	197,009.522	227,104.210	237,534.747	237,449.310	210,037.706	181,597.186	153,022.839	174,305.608	169,758.519	150,989.739	157,047.766	2,275,338.719

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED SALES

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	ANZA													
2	MW	5.712	7.488	10.608	10.404	9.948	9.684	6.852	5.388	8.860	8.093	7.071	6.304	96.412
3	MWH	3,733.956	3,974.280	4,547.868	5,266.380	5,087.034	4,309.788	3,861.588	3,682.884	4,682.804	4,126.590	3,963.021	4,047.215	51,283.408
4														
5	DUNCAN													
6	MW	3.860	6.040	6.960	5.940	6.620	5.360	4.020	2.780	4.300	3.900	3.900	3.500	57.180
7	MWH	2,004.660	2,422.840	3,223.350	2,960.420	2,955.880	2,300.600	1,919.560	1,905.850	2,292.120	2,226.640	1,883.390	1,984.450	28,079.760
8														
9	GRAHAM													
10	MW	20.966	31.511	39.951	39.726	36.986	32.263	24.988	18.448	20.642	19.992	18.818	20.271	324.562
11	MWH	10,775.112	12,244.130	18,499.166	17,976.098	17,655.323	13,801.595	11,076.763	10,334.556	12,000.020	11,134.378	9,221.331	11,677.543	156,396.015
12														
13	MOHAVE													
14	MW	131.516	139.516	146.516	168.516	169.516	160.516	138.516	108.516	115.516	114.800	110.800	89.800	1,594.044
15	CHEMSTAR O&M ADJ	0.000	0.000	0.000	0.000	0.000	(2.270)	0.000	0.000	0.000	(2.270)	0.000	(2.270)	(6.810)
16	POWER FACTOR ADJ	0.672	0.793	1.155	0.938	0.886	0.458	0.223	0.133	0.000	0.000	0.033	0.144	5.435
17	SCHED B O&M ADJ	0.000	23.765	33.100	11.400	10.300	19.000	8.800	0.300	3.600	3.065	5.400	12.000	130.730
18	ADJ MW	132.188	164.074	180.771	180.854	180.702	177.704	147.539	108.949	119.116	115.595	116.233	99.674	1,723.399
19	ENERGY MIN ADJ	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	12.000	4.000	39.000	4.000	59.000
20	ADJUSTED MWH	77,807.200	82,169.240	84,665.830	92,587.670	92,324.240	83,134.200	73,686.240	60,008.200	63,812.240	59,870.600	52,872.800	52,441.600	875,380.060
21														
22	SULPHUR													
23	MW	116.334	120.334	134.334	128.334	129.334	132.334	121.334	109.334	129.334	128.700	135.700	122.700	1,508.106
24	POWER FACTOR ADJ	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	SCHED B O&M ADJ	14.800	17.600	12.700	11.400	8.400	3.600	10.800	9.000	12.200	12.000	3.000	6.200	121.700
26	ADJ MW	131.134	137.934	147.034	139.734	137.734	135.934	132.134	118.334	141.534	140.700	138.700	128.900	1,629.806
27	ENERGY MIN ADJ	0.000	0.000	3.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3.000
28	ADJUSTED MWH	69,758.600	75,194.120	74,958.600	75,391.120	75,711.120	72,435.600	69,203.120	62,103.600	70,458.120	69,495.400	64,008.200	68,320.400	847,038.000
29														
30	TRICO													
31	MW	85.694	125.853	164.497	149.759	155.557	140.957	116.234	91.507	90.195	85.104	80.967	72.836	1,359.160
32	MWH	43,348.839	49,883.272	69,143.826	72,230.849	72,594.073	62,002.723	50,728.275	42,934.549	49,950.664	48,018.911	41,759.997	43,690.558	646,286.536
33														
34														
35														
36	FULL REQUIREMENTS													
37	MW	30.538	45.039	57.519	56.070	53.554	47.307	35.860	26.616	33.802	31.985	29.789	30.075	478.154
38	MWH	16,513.728	18,641.250	26,270.384	26,202.898	25,698.237	20,411.983	16,857.911	15,923.290	18,974.944	17,487.608	15,067.742	17,709.208	235,759.183
39											0.000		0.000	
40	PARTIAL REQUIREMENTS													
41	MW	349.016	427.861	492.302	470.347	473.993	454.595	395.907	318.790	350.845	341.399	335.900	301.410	4,712.365
42	MWH	190,914.639	207,246.632	228,768.256	240,209.639	240,629.433	217,572.523	193,617.635	165,046.349	184,221.024	177,384.911	158,640.997	164,452.558	2,368,704.596
43														
44														
45														
46	TOTAL CLASS A													
47	MW	379.554	472.900	549.821	526.417	527.547	501.902	431.767	345.406	384.647	373.384	365.689	331.485	5,190.519
48	MWH	207,428.367	225,887.882	255,038.640	266,412.537	266,327.670	237,984.506	210,475.546	180,969.639	203,195.968	194,872.519	173,708.739	182,161.766	2,604,463.779

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED BILLING DETERMINANTS

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	ANZA													
2	KW	5,712	7,488	10,608	10,404	9,948	9,684	6,852	5,388	8,860	8,093	7,071	6,304	96,412
3	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
4	KWH - BASE RESOURCES	3,516,089	3,974,280	4,058,041	5,070,048	4,966,884	4,304,383	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	3,076,659	49,283,270
5	KWH - OTHER EXISTING RESOURCES	217,867	0	489,827	196,332	104,947	0	0	0	0	0	0	970,556	1,979,530
6	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	15,203	5,405	0	0	0	0	0	0	20,608
7														
8	DUNCAN													
9	KW	3,860	6,040	6,960	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
10	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
11	KWH - BASE RESOURCES	1,887,693	2,422,840	2,876,180	2,850,055	2,886,066	2,297,715	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,508,562	26,956,670
12	KWH - OTHER EXISTING RESOURCES	116,967	0	347,170	110,365	60,981	0	0	0	0	0	0	475,888	1,111,371
13	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	8,834	2,885	0	0	0	0	0	0	11,719
14														
15	GRAHAM													
16	KW	20,966	31,511	39,951	39,726	36,986	32,263	24,988	18,448	20,642	19,992	18,818	20,271	324,562
17	KWH - TOTAL	10,775,112	12,244,130	18,499,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
18	KWH - BASE RESOURCES	10,146,411	12,244,130	16,506,717	17,305,943	17,238,326	13,784,286	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	8,877,170	149,870,030
19	KWH - OTHER EXISTING RESOURCES	628,701	0	1,992,449	670,155	364,234	(0)	0	0	0	0	0	2,800,373	6,455,912
20	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	52,763	17,309	0	0	0	0	0	0	70,073
21														
22	MOHAVE													
23	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
24	KWH - TOTAL	77,807,200	82,169,240	84,665,830	92,587,870	92,324,240	83,134,200	73,686,240	60,008,200	63,812,240	59,870,600	52,872,800	52,441,600	875,380,060
25	KWH - BASE RESOURCES	50,755,139	78,652,286	76,386,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
26	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,679,515
27	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
28														
29	SULPHUR													
30	KW	131,134	137,934	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	138,700	128,900	1,629,806
31	KWH - TOTAL	69,758,600	75,194,120	74,958,600	75,391,120	75,711,120	72,435,600	69,203,120	62,103,600	70,458,120	69,495,400	64,008,200	68,320,400	847,038,000
32	KWH - BASE RESOURCES	45,109,060	71,215,789	67,765,404	69,476,926	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	38,296,091	738,282,902
33	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
34	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	0	0	0	0	0	0	0	0	0
35														
36	TRICO													
37	KW	85,906	125,972	164,592	149,858	155,646	141,128	116,545	91,700	90,417	85,278	81,248	73,021	1,361,311
38	KWH - TOTAL	43,348,839	49,883,272	69,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
39	KWH - BASE RESOURCES	30,122,267	46,767,098	49,428,600	52,271,075	52,631,923	49,492,013	44,675,503	41,333,563	47,031,999	44,237,586	39,114,179	25,511,101	522,616,908
40	KWH - OTHER EXISTING RESOURCES	13,226,572	3,116,174	19,715,226	19,959,774	17,638,950	11,736,310	6,052,772	1,600,986	2,918,665	3,781,325	2,645,818	18,179,457	120,572,028
41	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,323,200	774,400	0	0	0	0	0	0	3,097,600
42														
43														
44														
45	FULL REQUIREMENTS													
46	KW	30,538	45,039	57,519	56,070	53,554	47,307	35,860	26,616	33,802	31,985	29,789	30,075	478,154
47	KWH - TOTAL	16,513,728	18,641,250	26,270,384	26,202,898	25,698,237	20,411,983	16,857,911	15,923,290	18,974,944	17,487,608	15,067,742	17,709,208	235,759,183
48	KWH - BASE RESOURCES	15,550,193	18,641,250	23,440,937	25,226,045	25,091,276	20,386,383	16,857,911	15,923,290	18,974,944	17,487,608	15,067,742	13,462,391	226,109,971
49	KWH - OTHER EXISTING RESOURCES	963,535	0	2,829,447	976,853	530,161	0	0	0	0	0	0	4,246,817	9,546,812
50	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	76,800	25,600	0	0	0	0	0	0	102,400
51														
52	PARTIAL REQUIREMENTS													
53	KW	349,228	427,980	492,397	470,446	474,082	454,766	396,218	318,983	351,067	341,573	336,181	301,595	4,714,516
54	KWH - TOTAL	190,914,639	207,246,632	228,768,256	240,209,639	240,629,433	217,572,523	193,617,635	165,046,349	184,221,024	177,384,911	158,640,997	164,452,558	2,368,704,596
55	KWH - BASE RESOURCES	125,986,466	196,635,172	193,580,372	202,444,905	204,086,654	194,808,354	177,344,709	158,592,167	174,348,179	165,355,446	149,053,374	103,364,555	2,045,600,355
56	KWH - OTHER EXISTING RESOURCES	64,928,173	10,611,460	35,187,884	37,764,734	34,219,579	21,989,769	16,272,926	6,454,182	9,872,845	12,029,465	9,587,623	61,088,003	320,006,641
57	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,323,200	774,400	0	0	0	0	0	0	3,097,600
58														
59	TOTAL CLASS A													
60	KW	379,766	473,019	549,916	526,516	527,636	502,073	432,078	345,599	384,869	373,558	365,970	331,670	5,192,670
61	KWH - TOTAL	207,428,367	225,887,882	255,038,640	266,412,537	266,327,670	237,984,506	210,475,546	180,969,639	203,195,968	194,872,519	173,708,739	182,161,766	2,604,463,779
62	KWH - BASE RESOURCES	141,536,659	215,276,422	217,021,309	227,670,950	229,177,930	215,194,737	194,202,620	174,515,457	193,323,123	182,843,054	164,121,116	116,826,946	2,271,710,326
63	KWH - OTHER EXISTING RESOURCES	65,891,708	10,611,460	38,017,331	38,741,587	34,749,740	21,989,769	16,272,926	6,454,182	9,872,845	12,029,465	9,587,623	65,334,820	329,553,453
64	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,400,000	800,000	0	0	0	0	0	0	3,200,000

Arizona Electric Power Cooperative, Inc.

ANZA ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	6,468	6,132	9,936	11,832	10,716	9,036	5,592	6,564	9,156	7,440	7,596	6,408	96,876
3	kW - Current Year	5,712	7,488	10,608	10,404	9,948	9,684	6,852	5,388	8,860	8,093	7,071	6,304	96,412
4	kW - 12 Month Average	8,010	8,123	8,179	8,060	7,996	8,050	8,155	8,057	8,032	8,087	8,043	8,034	96,826
5	ARM Load Ratio Share	20.19%	20.31%	20.41%	20.15%	20.01%	19.97%	20.29%	20.12%	20.13%	20.26%	20.23%	20.16%	20.19%
6	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
7	KWH - BASE RESOURCES	3,516,089	3,974,280	4,058,041	5,070,048	4,966,884	4,304,383	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	3,076,659	49,283,270
8	KWH - OTHER EXISTING RESOURCES	217,867	0	489,827	196,332	104,947	0	0	0	0	0	0	970,556	1,979,530
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	15,203	5,405	0	0	0	0	0	0	20,608
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$85,566	$112,170	$158,908	$155,852	$149,021	$145,066	$102,643	$80,712	$132,723	$121,233	$105,924	$94,434	$1,444,252
19	Base Energy Charge Revenue	77,405	82,387	94,277	109,172	105,454	89,342	80,051	76,346	97,075	85,544	82,153	83,899	1,063,105
20	Total Present Base Rate Revenue	$162,971	$194,557	$253,185	$265,024	$254,475	$234,408	$182,694	$157,058	$229,797	$206,777	$188,077	$178,333	$2,507,357
21	FPPCA	47,496	50,553	67,127	77,732	75,085	63,612	103,259	98,480	125,218	110,345	105,971	108,223	1,033,100
22	Total Present Revenue	$210,467	$245,110	$320,312	$342,756	$329,560	$298,021	$285,953	$255,539	$355,016	$317,122	$294,048	$286,555	$3,540,457
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$50,714	$51,009	$51,273	$50,623	$50,264	$50,163	$50,955	$50,527	$50,561	$50,893	$50,799	$50,644	$608,426
34	O&M Demand Charge Revenue	83,595	84,083	84,517	83,445	82,854	82,687	83,992	83,288	83,344	83,890	83,736	83,480	1,002,912
35	Base Resource Energy Revenue	110,960	125,420	128,063	160,000	156,744	135,837	121,863	116,224	147,779	130,226	125,064	97,093	1,555,271
36	Other Existing Resources Energy Revenue	13,442	0	30,221	12,113	6,475	0	0	0	0	0	0	59,880	122,130
37	Additional ARM Resources	0	0	0	0	938	333	0	0	0	0	0	0	1,271
38	Total Proposed Base Rate Revenue	$258,711	$260,512	$294,074	$306,180	$297,275	$269,021	$256,810	$250,039	$281,684	$265,008	$259,600	$291,097	$3,290,011
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$258,711	$260,512	$294,074	$306,180	$297,275	$269,021	$256,810	$250,039	$281,684	$265,008	$259,600	$291,097	$3,290,011
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$48,743	$22,922	($23,118)	($21,784)	($15,903)	($12,216)	$32,304	$53,103	$1,182	$13,549	$28,612	$39,690	$167,086
44	Change in Base Energy Charge Revenue	46,997	43,033	64,006	62,940	58,703	46,828	41,812	39,878	50,704	44,682	42,911	73,074	615,568
45	Change in Base Rate Revenue	$95,740	$65,955	$40,889	$41,156	$42,800	$34,613	$74,117	$92,981	$51,887	$58,231	$71,523	$112,764	$782,654
46	Change in FPPCA Revenue	(47,496)	(50,553)	(67,127)	(77,732)	(75,085)	(63,612)	(103,259)	(98,480)	(125,218)	(110,345)	(105,971)	(108,223)	(1,033,100)
47	Change in Total Revenue	$48,244	$15,402	($26,238)	($36,576)	($32,285)	($29,000)	($29,142)	($5,500)	($73,331)	($52,114)	($34,448)	$4,541	($250,447)
48	Percentage Change in Base Rate Revenue	58.75%	33.90%	16.15%	15.53%	16.82%	14.77%	40.57%	59.20%	22.58%	28.16%	38.03%	63.23%	31.21%
49	Percentage Change in Total Revenue	22.92%	6.28%	-8.19%	-10.67%	-9.80%	-9.73%	-10.19%	-2.15%	-20.66%	-16.43%	-11.72%	1.58%	-7.07%

Arizona Electric Power Cooperative, Inc.

DUNCAN ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	3,100	5,640	6,660	6,020	6,520	3,720	4,520	3,320	4,520	4,320	4,180	3,260	55,780
3	kW - Current Year	3,860	6,040	6,960	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
4	kW - 12 Month Average	4,712	4,745	4,770	4,763	4,772	4,908	4,867	4,822	4,803	4,768	4,745	4,765	57,440
5	ARM Load Ratio Share	11.88%	11.86%	11.91%	11.91%	11.94%	12.18%	12.11%	12.04%	12.04%	11.95%	11.93%	11.96%	11.98%
6	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
7	KWH - BASE RESOURCES	1,887,693	2,422,840	2,876,180	2,850,055	2,886,066	2,297,715	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,508,562	26,956,670
8	KWH - OTHER EXISTING RESOURCES	116,967	0	347,170	110,365	60,981	0	0	0	0	0	0	475,888	1,111,371
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	8,834	2,885	0	0	0	0	0	0	11,719
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$57,823	$90,479	$104,261	$88,981	$99,168	$80,293	$60,220	$41,644	$64,414	$58,422	$58,422	$52,430	$856,556
19	Base Energy Charge Revenue	41,557	50,225	66,820	61,370	61,275	47,691	39,792	39,508	47,516	46,158	39,043	41,138	582,093
20	Total Present Base Rate Revenue	$99,379	$140,705	$171,081	$150,351	$160,443	$127,984	$100,012	$81,153	$111,930	$104,580	$97,465	$93,568	$1,438,650
21	FPPCA	25,499	30,819	47,577	43,696	43,629	33,957	51,329	50,962	61,291	59,540	50,362	53,064	551,725
22	Total Present Revenue	$124,879	$171,523	$218,657	$194,047	$204,072	$161,941	$151,341	$132,115	$173,221	$164,121	$147,827	$146,632	$1,990,375
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$29,831	$29,797	$29,903	$29,917	$29,995	$30,586	$30,408	$30,238	$30,236	$30,009	$29,969	$30,036	$360,925
34	O&M Demand Charge Revenue	49,173	49,116	49,290	49,315	49,444	50,417	50,124	49,843	49,840	49,465	49,401	49,510	594,939
35	Base Resource Energy Revenue	59,571	76,459	90,766	89,941	91,078	72,511	60,577	60,144	72,334	70,268	59,436	47,607	850,693
36	Other Existing Resources Energy Revenue	7,216	0	21,419	6,809	3,762	0	0	0	0	0	0	29,361	68,568
37	Additional ARM Resources	0	0	0	0	545	178	0	0	0	0	0	0	723
38	Total Proposed Base Rate Revenue	$145,792	$155,373	$191,378	$175,982	$174,824	$153,692	$141,110	$140,226	$152,409	$149,742	$138,806	$156,514	$1,875,847
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$145,792	$155,373	$191,378	$175,982	$174,824	$153,692	$141,110	$140,226	$152,409	$149,742	$138,806	$156,514	$1,875,847
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$21,181	($11,566)	($25,068)	($9,749)	($19,728)	$710	$20,313	$38,437	$15,661	$21,052	$20,948	$27,116	$99,307
44	Change in Base Energy Charge Revenue	25,231	26,234	45,365	35,381	34,110	24,997	20,785	20,636	24,819	24,110	20,393	35,830	337,890
45	Change in Base Rate Revenue	$46,412	$14,668	$20,297	$25,632	$14,381	$25,708	$41,098	$59,073	$40,480	$45,162	$41,341	$62,946	$437,197
46	Change in FPPCA Revenue	(25,499)	(30,819)	(47,577)	(43,696)	(43,629)	(33,957)	(51,329)	(50,962)	(61,291)	(59,540)	(50,362)	(53,064)	(551,725)
47	Change in Total Revenue	$20,913	($16,151)	($27,279)	($18,064)	($29,248)	($8,249)	($10,231)	$8,110	($20,811)	($14,379)	($9,021)	$9,882	($114,528)
48	Percentage Change in Base Rate Revenue	46.70%	10.42%	11.86%	17.05%	8.96%	20.09%	41.09%	72.79%	36.17%	43.18%	42.42%	67.27%	30.39%
49	Percentage Change in Total Revenue	16.75%	-9.42%	-12.48%	-9.31%	-14.33%	-5.09%	-6.76%	6.14%	-12.01%	-8.76%	-6.10%	6.74%	-5.75%

Arizona Electric Power Cooperative, Inc.

GRAHAM ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	21,235	29,349	40,099	39,125	36,733	30,341	27,052	18,498	21,918	20,119	19,731	19,458	323,658
3	kW - Current Year	20,966	31,511	39,951	39,726	36,986	32,263	24,988	18,448	20,642	19,992	18,818	20,271	324,562
4	kW - 12 Month Average	26,949	27,129	27,117	27,167	27,188	27,348	27,176	27,172	27,066	27,055	26,979	27,047	325,394
5	ARM Load Ratio Share	67.93%	67.83%	67.68%	67.93%	68.05%	67.85%	67.61%	67.84%	67.83%	67.79%	67.84%	67.88%	67.84%
6	KWH - TOTAL	10,775,112	12,244,130	18,499,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
7	KWH - BASE RESOURCES	10,146,411	12,244,130	16,506,717	17,305,943	17,238,326	13,784,286	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	8,877,170	149,870,030
8	KWH - OTHER EXISTING RESOURCES	628,701	0	1,992,449	670,155	364,234	(0)	0	0	0	0	0	2,800,373	6,455,912
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	52,763	17,309	0	0	0	0	0	0	70,073
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$314,071	$472,035	$598,466	$595,095	$554,050	$483,300	$374,320	$276,351	$309,217	$299,480	$281,894	$303,660	$4,861,939
19	Base Energy Charge Revenue	223,368	253,821	383,488	372,645	365,995	286,107	229,621	214,235	248,760	230,816	191,158	242,075	3,242,089
20	Total Present Base Rate Revenue	$537,439	$725,856	$981,954	$967,740	$920,045	$769,407	$603,942	$490,586	$557,978	$530,296	$473,052	$545,735	$8,104,028
21	FPPCA	137,059	155,745	273,048	265,327	260,593	203,712	296,193	276,346	320,881	297,733	246,578	312,257	3,045,472
22	Total Present Revenue	$674,498	$881,601	$1,255,001	$1,233,067	$1,180,638	$973,118	$900,134	$766,932	$878,858	$828,029	$719,630	$857,993	$11,149,500
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$170,623	$170,362	$169,992	$170,628	$170,909	$170,419	$169,805	$170,403	$170,371	$170,267	$170,399	$170,488	$2,044,667
34	O&M Demand Charge Revenue	281,251	280,820	280,211	281,259	281,721	280,914	279,902	280,887	280,835	280,663	280,882	281,028	3,370,373
35	Base Resource Energy Revenue	320,198	386,398	520,916	546,137	544,003	435,002	349,558	326,136	378,694	351,376	291,005	280,144	4,729,567
36	Other Existing Resources Energy Revenue	38,789	0	122,927	41,346	22,472	(0)	0	0	0	0	0	172,773	398,307
37	Additional ARM Resources	0	0	0	0	3,255	1,068	0	0	0	0	0	0	4,323
38	Total Proposed Base Rate Revenue	$810,861	$837,579	$1,094,046	$1,039,371	$1,022,360	$887,403	$799,265	$777,426	$829,901	$802,307	$742,286	$904,433	$10,547,237
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$810,861	$837,579	$1,094,046	$1,039,371	$1,022,360	$887,403	$799,265	$777,426	$829,901	$802,307	$742,286	$904,433	$10,547,237
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$137,803	($20,853)	($148,263)	($143,208)	($101,421)	($31,967)	$75,387	$174,939	$141,989	$151,450	$169,387	$147,857	$553,101
44	Change in Base Energy Charge Revenue	135,619	132,577	260,355	214,839	203,736	149,962	119,937	111,900	129,934	120,561	99,847	210,842	1,890,108
45	Change in Base Rate Revenue	$273,422	$111,724	$112,092	$71,631	$102,315	$117,996	$195,324	$286,840	$271,923	$272,011	$269,234	$358,698	$2,443,209
46	Change in FPPCA Revenue	(137,059)	(155,745)	(273,048)	(265,327)	(260,593)	(203,712)	(296,193)	(276,346)	(320,881)	(297,733)	(246,578)	(312,257)	(3,045,472)
47	Change in Total Revenue	$136,363	($44,022)	($160,955)	($193,696)	($158,277)	($85,716)	($100,869)	$10,494	($48,958)	($25,722)	$22,656	$46,441	($602,263)
48	Percentage Change in Base Rate Revenue	50.88%	15.39%	11.42%	7.40%	11.12%	15.34%	32.34%	58.47%	48.73%	51.29%	56.91%	65.73%	30.15%
49	Percentage Change in Total Revenue	20.22%	-4.99%	-12.83%	-15.71%	-13.41%	-8.81%	-11.21%	1.37%	-5.57%	-3.11%	3.15%	5.41%	-5.40%

Arizona Electric Power Cooperative, Inc.

MOHAVE ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.011050	$0.011050	$0.013050	$0.013050	$0.013050	$0.013050	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$855,113	$855,113	$855,113	$855,113	$855,113	$841,539	$855,113	$855,113	$855,113	$841,248	$855,113	$841,405	$10,220,208
7														
8	**PRESENT REVENUES**													
9	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
10	KWH - BASE RESOURCES	50,755,139	78,652,286	76,386,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
11	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,679,515
12	Demand Revenue	$1,814,798	$2,046,290	$2,167,510	$2,168,113	$2,167,010	$2,131,670	$1,926,246	$1,646,083	$1,719,895	$1,680,468	$1,698,967	$1,565,038	$22,732,087
13	Base Energy Charge Revenue	1,612,943	1,703,368	1,755,123	1,919,342	1,913,881	1,723,372	1,527,516	1,243,970	1,322,828	1,241,118	1,096,053	1,087,114	18,146,629
14	Total Present Base Rate Revenue	$3,427,741	$3,749,659	$3,922,633	$4,087,455	$4,080,891	$3,855,042	$3,453,762	$2,890,053	$3,042,723	$2,921,585	$2,795,020	$2,652,152	$40,878,716
15	FPPCA	859,770	907,970	1,104,889	1,208,269	1,204,831	1,084,901	1,879,736	1,530,809	1,627,850	1,527,299	1,348,785	1,337,785	15,622,895
16	Total Present Revenue	$4,287,511	$4,657,629	$5,027,522	$5,295,725	$5,285,722	$4,939,943	$5,333,498	$4,420,862	$4,670,573	$4,448,884	$4,143,805	$3,989,937	$56,501,611
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	
20	O&M Demand Charge	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	
21	Base Resource Energy Charge	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	
22	Other Existing Resources Energy Charge	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$9,179,703
27	O&M Demand Charge Revenue	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	15,298,589
28	Base Resource Energy Revenue	1,631,645	2,528,466	2,455,622	2,594,195	2,612,518	2,472,658	2,217,326	1,887,770	2,008,670	1,871,542	1,673,996	1,271,666	25,226,075
29	Other Existing Resources Energy Revenue	1,860,829	241,921	569,519	817,930	760,603	427,710	324,157	88,450	91,425	113,708	55,049	886,267	6,237,567
30	Total Proposed Base Rate Revenue	$5,532,332	$4,810,244	$5,064,999	$5,451,982	$5,412,978	$4,940,226	$4,581,341	$4,016,078	$4,139,952	$4,025,108	$3,768,902	$4,197,791	$55,941,934
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$5,532,332	$4,810,244	$5,064,999	$5,451,982	$5,412,978	$4,940,226	$4,581,341	$4,016,078	$4,139,952	$4,025,108	$3,768,902	$4,197,791	$55,941,934
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$225,060	($6,433)	($127,653)	($128,255)	($127,152)	($91,812)	$113,612	$393,775	$319,962	$359,390	$340,891	$474,820	$1,746,204
36	Change in Energy Charge Revenue	1,879,531	1,067,018	1,270,019	1,492,782	1,459,239	1,176,997	1,013,968	732,250	777,267	744,133	632,991	1,070,819	13,317,014
37	Change in Base Rate Revenue	$2,104,591	$1,060,585	$1,142,366	$1,364,527	$1,332,087	$1,085,184	$1,127,579	$1,126,025	$1,097,230	$1,103,523	$973,882	$1,545,639	$15,063,218
38	Change in FPPCA Revenue	(859,770)	(907,970)	(1,104,889)	(1,208,269)	(1,204,831)	(1,084,901)	(1,879,736)	(1,530,809)	(1,627,850)	(1,527,299)	(1,348,785)	(1,337,785)	(15,622,895)
39	Change in Total Revenue	$1,244,821	$152,615	$37,477	$156,258	$127,256	$283	($752,157)	($404,784)	($530,621)	($423,776)	($374,903)	$207,854	($559,677)
40	Percentage Change in Base Rate Revenue	61.40%	28.28%	29.12%	33.38%	32.64%	28.15%	32.65%	38.96%	36.06%	37.77%	34.84%	58.28%	36.85%
41	Percentage Change in Total Revenue	29.03%	3.28%	0.75%	2.95%	2.41%	0.01%	-14.10%	-9.16%	-11.36%	-9.53%	-9.05%	5.21%	-0.99%

Arizona Electric Power Cooperative, Inc.

SULPHUR SPRINGS ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.011050	$0.011050	$0.013050	$0.013050	$0.013050	$0.013050	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	$0.025510	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$9,089,148
7														
8	**PRESENT REVENUES**													
9	KW	131,134	137,934	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	138,700	128,900	1,629,806
10	KWH - BASE RESOURCES	45,109,060	71,215,789	67,765,404	69,476,926	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	38,296,091	738,282,902
11	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
12	Demand Revenue	$1,709,482	$1,758,830	$1,824,896	$1,771,898	$1,757,378	$1,744,310	$1,716,722	$1,616,534	$1,784,966	$1,778,911	$1,764,391	$1,693,243	$20,921,540
13	Base Energy Charge Revenue	1,446,096	1,558,774	1,553,892	1,562,858	1,569,492	1,501,590	1,434,581	1,287,408	1,460,597	1,440,640	1,326,890	1,416,282	17,559,098
14	Total Present Base Rate Revenue	$3,155,558	$3,317,604	$3,378,788	$3,334,756	$3,326,869	$3,245,900	$3,151,303	$2,903,941	$3,245,563	$3,219,551	$3,091,281	$3,109,525	$38,480,637
15	FPPCA	770,833	830,895	978,210	983,854	988,030	945,285	1,765,372	1,584,263	1,797,387	1,772,828	1,632,849	1,742,853	15,792,657
16	Total Present Revenue	$3,926,390	$4,148,499	$4,356,997	$4,318,610	$4,314,899	$4,191,184	$4,916,674	$4,488,204	$5,042,949	$4,992,378	$4,724,130	$4,852,378	$54,273,295
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	
20	O&M Demand Charge	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	
21	Base Resource Energy Charge	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	
22	Other Existing Resources Energy Charge	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$8,128,396
27	O&M Demand Charge Revenue	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	13,546,516
28	Base Resource Energy Revenue	1,456,357	2,299,219	2,187,822	2,243,079	2,266,032	2,208,312	2,056,423	1,889,857	2,093,151	2,030,752	1,868,240	1,236,399	23,835,642
29	Other Existing Resources Energy Revenue	1,645,489	265,575	480,184	394,804	368,707	269,395	367,667	238,139	375,504	440,258	409,980	2,004,284	7,259,986
30	Total Proposed Base Rate Revenue	$4,908,089	$4,371,037	$4,474,250	$4,444,126	$4,440,982	$4,283,950	$4,230,332	$3,934,239	$4,274,897	$4,277,252	$4,084,462	$5,046,925	$52,770,540
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$4,908,089	$4,371,037	$4,474,250	$4,444,126	$4,440,982	$4,283,950	$4,230,332	$3,934,239	$4,274,897	$4,277,252	$4,084,462	$5,046,925	$52,770,540
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$96,781	$47,413	($18,653)	$34,345	$48,865	$61,933	$89,521	$189,709	$21,277	$27,332	$41,852	$113,000	$753,372
36	Change in Energy Charge Revenue	1,655,750	1,006,020	1,114,115	1,075,026	1,065,248	976,117	989,509	840,589	1,008,058	1,030,370	951,329	1,824,400	13,536,530
37	Change in Base Rate Revenue	$1,752,531	$1,053,433	$1,095,462	$1,109,370	$1,114,112	$1,038,050	$1,079,030	$1,030,298	$1,029,335	$1,057,701	$993,181	$1,937,400	$14,289,903
38	Change in FPPCA Revenue	(770,833)	(830,895)	(978,210)	(983,854)	(988,030)	(945,285)	(1,765,372)	(1,584,263)	(1,797,387)	(1,772,828)	(1,632,849)	(1,742,853)	(15,792,657)
39	Change in Total Revenue	$981,698	$222,538	$117,252	$125,516	$126,082	$92,765	($686,342)	($553,965)	($768,052)	($715,126)	($639,668)	$194,547	($1,502,755)
40	Percentage Change in Base Rate Revenu	55.54%	31.75%	32.42%	33.27%	33.49%	31.98%	34.24%	35.48%	31.72%	32.85%	32.13%	62.31%	37.14%
41	Percentage Change in Total Revenue	25.00%	5.36%	2.69%	2.91%	2.92%	2.21%	-13.96%	-12.34%	-15.23%	-14.32%	-13.54%	4.01%	-2.77%

Arizona Electric Power Cooperative, Inc.

TRICO ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	88,830	110,939	146,640	163,888	146,704	139,833	110,067	87,080	92,923	87,572	84,462	69,545	1,328,483
3	kW - Current Year	85,906	125,972	164,592	149,858	155,646	141,128	116,545	91,700	90,417	85,278	81,248	73,021	1,361,311
4	kW - 12 Month Average	110,463	111,716	113,212	112,043	112,788	112,896	113,436	113,821	113,612	113,421	113,153	113,443	1,354,003
5	ARM Load Ratio Share	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	KWH - TOTAL	43,348,839	49,883,272	69,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
7	KWH - BASE RESOURCES	30,122,267	46,767,098	49,428,600	52,271,075	52,631,923	49,492,013	44,675,503	41,333,563	47,031,999	44,237,586	39,114,179	25,511,101	522,616,908
8	KWH - OTHER EXISTING RESOURCES	13,226,572	3,116,174	19,715,226	19,959,774	17,638,950	11,736,310	6,052,772	1,600,986	2,918,665	3,781,325	2,645,818	18,179,457	120,572,028
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,323,200	774,400	0	0	0	0	0	0	3,097,600
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.012720	$0.012720	$0.014760	$0.014760	$0.014760	$0.014760	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	$0.026740	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$1,286,872	$1,887,061	$2,465,588	$2,244,873	$2,331,577	$2,114,097	$1,745,844	$1,373,666	$1,354,447	$1,277,464	$1,217,095	$1,093,855	$20,392,439
19	Base Energy Charge Revenue	898,621	1,034,080	1,433,352	1,497,345	1,504,875	1,285,316	1,051,597	890,033	1,035,477	995,432	865,685	905,705	13,397,520
20	Total Present Base Rate Revenue	$2,185,493	$2,921,141	$3,898,940	$3,742,218	$3,836,452	$3,399,414	$2,797,441	$2,263,699	$2,389,924	$2,272,896	$2,082,780	$1,999,560	$33,789,959
21	FPPCA	551,397	634,515	1,020,563	1,066,127	1,071,489	915,160	1,356,474	1,148,070	1,335,681	1,284,026	1,116,662	1,168,286	12,668,450
22	Total Present Revenue	$2,736,891	$3,555,656	$4,919,503	$4,808,346	$4,907,941	$4,314,574	$4,153,915	$3,411,769	$3,725,605	$3,556,922	$3,199,442	$3,167,845	$46,458,408
23														
24	**PROPOSED RATES**													
25	Fixed Demand Charge	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	
26	O&M Demand Charge	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	
27	Base Resource Energy Charge	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	
28	Other Existing Resources Energy Charge	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	
29	Additional ARM Resources	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES**													
33	Fixed Demand Charge Revenue	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$8,159,241
34	O&M Demand Charge Revenue	$764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	9,173,582
35	Base Resource Energy Revenue	975,449	1,514,458	1,600,645	1,692,693	1,704,378	1,602,698	1,446,726	1,338,504	1,523,036	1,432,544	1,266,633	826,125	16,923,888
36	Other Existing Resources Energy Revenue	873,507	205,798	1,302,030	1,318,181	1,164,909	775,088	399,736	105,732	192,754	249,726	174,735	1,200,605	7,962,802
37	Additional ARM Resources	0	0	0	0	153,428	51,143	0	0	0	0	0	0	204,571
38	Total Proposed Base Rate Revenue	$3,293,358	$3,164,657	$4,347,077	$4,455,275	$4,467,118	$3,873,331	$3,290,864	$2,888,638	$3,160,192	$3,126,672	$2,885,770	$3,471,132	$42,424,084
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$3,293,358	$3,164,657	$4,347,077	$4,455,275	$4,467,118	$3,873,331	$3,290,864	$2,888,638	$3,160,192	$3,126,672	$2,885,770	$3,471,132	$42,424,084
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$157,530	($442,659)	($1,021,186)	($800,471)	($887,175)	($669,696)	($301,442)	$70,736	$89,955	$166,937	$227,307	$350,547	($3,059,616)
44	Change in Base Energy Charge Revenue	950,335	686,175	1,469,324	1,513,528	1,517,841	1,143,613	794,865	554,202	680,313	686,838	575,683	1,121,025	11,693,741
45	Change in Base Rate Revenue	$1,107,865	$243,517	$448,137	$713,057	$630,665	$473,917	$493,423	$624,938	$770,268	$853,776	$802,990	$1,471,573	$8,634,126
46	Change in FPPCA Revenue	(551,397)	(634,515)	(1,020,563)	(1,066,127)	(1,071,489)	(915,160)	(1,356,474)	(1,148,070)	(1,335,681)	(1,284,026)	(1,116,662)	(1,168,286)	(12,668,450)
47	Change in Total Revenue	$556,467	($390,999)	($572,425)	($353,070)	($440,823)	($441,243)	($863,052)	($523,131)	($565,413)	($430,250)	($313,672)	$303,287	($4,034,324)
48	Percentage Change in Base Rate Revenue	50.69%	8.34%	11.49%	19.05%	16.44%	13.94%	17.64%	27.61%	32.23%	37.56%	38.55%	73.59%	25.55%
49	Percentage Change in Total Revenue	20.33%	-11.00%	-11.64%	-7.34%	-8.98%	-10.23%	-20.78%	-15.33%	-15.18%	-12.10%	-9.80%	9.57%	-8.68%

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED PRESENT WITH ACTUAL FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	PRESENT REVENUES													
2	FULL REQUIREMENTS													
3	Demand Revenue	$457,459	$674,684	$861,635	$839,929	$802,239	$706,659	$537,183	$398,708	$506,354	$479,135	$446,239	$450,524	$7,162,747
4	Base Energy Revenue	342,330	386,433	544,585	543,186	532,724	423,140	349,464	330,090	393,351	362,518	312,354	367,112	4,887,288
5	Total Present Base Rate Revenue	$799,789	$1,061,117	$1,406,220	$1,383,115	$1,334,963	$1,131,799	$886,647	$728,797	$899,705	$841,653	$758,594	$817,635	$12,050,035
6	FPPCA	210,055	237,117	387,751	386,755	379,306	301,281	450,781	425,789	507,390	467,619	402,911	473,544	4,630,297
7	Total Adjusted Present Revenue	$1,009,843	$1,298,234	$1,793,971	$1,769,869	$1,714,269	$1,433,080	$1,337,428	$1,154,586	$1,407,095	$1,309,272	$1,161,505	$1,291,180	$16,680,332
8														
9	PARTIAL REQUIREMENTS													
10	Fixed / O&M Charge Revenue	$4,811,132	$5,692,181	$6,457,994	$6,184,884	$6,255,964	$5,990,077	$5,388,812	$4,636,283	$4,859,308	$4,736,843	$4,680,453	$4,352,135	$64,046,066
11	Base Energy Revenue	3,957,660	4,296,223	4,742,366	4,979,546	4,988,248	4,510,278	4,013,694	3,421,411	3,818,902	3,677,189	3,288,628	3,409,102	49,103,246
12	Total Present Base Rate Revenue	$8,768,792	$9,988,403	$11,200,360	$11,164,430	$11,244,213	$10,500,356	$9,402,506	$8,057,693	$8,678,209	$8,414,032	$7,969,081	$7,761,237	$113,149,312
13	FPPCA	2,181,999	2,373,380	3,103,662	3,258,251	3,264,350	2,945,346	5,001,582	4,263,142	4,760,918	4,584,152	4,098,297	4,248,924	44,084,002
14	Total Adjusted Present Revenue	$10,950,791	$12,361,784	$14,304,022	$14,422,680	$14,508,563	$13,445,702	$14,404,087	$12,320,835	$13,439,127	$12,998,185	$12,067,377	$12,010,161	$157,233,314
15														
16	TOTAL CLASS A													
17	Demand Revenue	$5,268,591	$6,366,865	$7,319,629	$7,024,812	$7,058,203	$6,698,736	$5,925,995	$5,034,990	$5,365,662	$5,215,978	$5,126,692	$4,802,659	$71,208,813
18	Base Energy Revenue	4,299,990	4,682,656	5,286,951	5,522,732	5,520,973	4,933,419	4,363,158	3,751,501	4,212,252	4,039,707	3,600,982	3,776,213	53,990,534
19	Total Present Base Rate Revenue	$9,568,581	$11,049,521	$12,606,580	$12,547,544	$12,579,176	$11,632,155	$10,289,153	$8,786,491	$9,577,914	$9,255,686	$8,727,674	$8,578,872	$125,199,347
20	FPPCA	2,392,054	2,610,497	3,491,413	3,645,005	3,643,656	3,246,627	5,452,362	4,688,931	5,268,308	5,051,771	4,501,208	4,722,468	48,714,300
21	Total Adjusted Present Revenue	$11,960,635	$13,660,018	$16,097,993	$16,192,550	$16,222,832	$14,878,782	$15,741,515	$13,475,422	$14,846,222	$14,307,457	$13,228,882	$13,301,341	$173,913,646
22														
23	PROPOSED REVENUES													
24	FULL REQUIREMENTS													
25	Demand Revenue	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$7,982,241
26	Base Energy Revenue	550,177	588,277	914,311	856,347	829,273	644,929	531,998	502,504	598,807	551,870	475,505	686,857	7,730,854
27	Total Proposed Base Rate Revenue	$1,215,363	$1,253,463	$1,579,498	$1,521,533	$1,494,459	$1,310,115	$1,197,185	$1,167,691	$1,263,994	$1,217,057	$1,140,691	$1,352,044	$15,713,095
28	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total Adjusted Proposed Revenue	$1,215,363	$1,253,463	$1,579,498	$1,521,533	$1,494,459	$1,310,115	$1,197,185	$1,167,691	$1,263,994	$1,217,057	$1,140,691	$1,352,044	$15,713,095
30														
31	PARTIAL REQUIREMENTS													
32	Fixed / O&M Charge Revenue	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$63,486,027
33	Base Energy Revenue	8,443,276	7,055,436	8,595,823	9,060,881	9,030,576	7,807,005	6,812,035	5,548,452	6,284,539	6,138,530	5,448,632	7,425,346	87,650,532
34	Total Proposed Base Rate Revenue	$13,733,778	$12,345,938	$13,886,326	$14,351,384	$14,321,078	$13,097,507	$12,102,537	$10,838,955	$11,575,041	$11,429,032	$10,739,134	$12,715,848	$151,136,559
35	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total Adjusted Proposed Revenue	$13,733,778	$12,345,938	$13,886,326	$14,351,384	$14,321,078	$13,097,507	$12,102,537	$10,838,955	$11,575,041	$11,429,032	$10,739,134	$12,715,848	$151,136,559
37														
38	TOTAL CLASS A													
39	Demand Revenue	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$71,468,267
40	Base Energy Revenue	8,993,452	7,643,712	9,510,135	9,917,228	9,859,848	8,451,934	7,344,034	6,050,956	6,883,347	6,690,400	5,924,137	8,112,203	95,381,386
41	Total Proposed Base Rate Revenue	$14,949,141	$13,599,401	$15,465,824	$15,872,917	$15,815,537	$14,407,622	$13,299,722	$12,006,645	$12,839,036	$12,646,089	$11,879,826	$14,067,892	$166,849,654
42	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Adjusted Proposed Revenue	$14,949,141	$13,599,401	$15,465,824	$15,872,917	$15,815,537	$14,407,622	$13,299,722	$12,006,645	$12,839,036	$12,646,089	$11,879,826	$14,067,892	$166,849,654
44														
45	PROPOSED REVENUE CHANGES													
46	FULL REQUIREMENTS													
47	Demand Revenue	$207,727	($9,497)	($196,448)	($174,742)	($137,052)	($43,472)	$128,004	$266,479	$158,833	$186,051	$218,948	$214,663	$819,494
48	Base Energy Revenue	207,847	201,844	369,726	313,161	296,548	221,788	182,534	172,414	205,457	189,352	163,150	319,745	2,843,566
49	Change in Base Rate Revenue	$415,574	$192,346	$173,278	$138,419	$159,496	$178,316	$310,538	$438,893	$364,290	$375,404	$382,098	$534,409	$3,663,060
50	FPPCA	(210,055)	(237,117)	(387,751)	(386,755)	(379,306)	(301,281)	(450,781)	(425,789)	(507,390)	(467,619)	(402,911)	(473,544)	(4,630,297)
51	Total Revenue Change	$205,520	($44,771)	($214,473)	($248,336)	($219,810)	($122,965)	($140,243)	$13,104	($143,100)	($92,215)	($20,814)	$60,864	($967,237)
52	Percent Change in Base Rate Revenue	4.74%	1.93%	1.55%	1.24%	1.42%	1.70%	3.30%	5.45%	4.20%	4.46%	4.79%	6.89%	3.24%
53	Percent Change in Total Revenue	20.35%	-3.45%	-11.96%	-14.03%	-12.82%	-8.58%	-10.49%	1.13%	-10.17%	-7.04%	-1.79%	4.71%	-5.80%
54														
55	PARTIAL REQUIREMENTS													
56	Fixed / O&M Charge Revenue	$479,371	($401,678)	($1,167,492)	($894,381)	($965,462)	($699,575)	($98,310)	$654,220	$431,195	$553,659	$610,049	$938,367	($560,039)
57	Base Energy Revenue	4,485,615	2,759,213	3,853,458	4,081,336	4,042,327	3,296,726	2,798,342	2,127,042	2,465,637	2,461,341	2,160,004	4,016,245	38,547,286
58	Change in Base Rate Revenue	$4,964,986	$2,357,535	$2,685,965	$3,186,954	$3,076,865	$2,597,152	$2,700,032	$2,781,261	$2,896,832	$3,015,000	$2,770,053	$4,954,611	$37,987,247
59	FPPCA	(2,181,999)	(2,373,380)	(3,103,662)	(3,258,251)	(3,264,350)	(2,945,346)	(5,001,582)	(4,263,142)	(4,760,918)	(4,584,152)	(4,098,297)	(4,248,924)	(44,084,002)
60	Total Revenue Change	$2,782,987	($15,846)	($417,696)	($71,296)	($187,485)	($348,195)	($2,301,550)	($1,481,881)	($1,864,086)	($1,569,152)	($1,328,243)	$705,687	($6,096,756)
61	Percent Change in Base Rate Revenue	56.62%	23.60%	23.98%	28.55%	27.36%	24.73%	28.72%	34.52%	33.38%	35.83%	34.76%	63.84%	33.57%
62	Percent Change in Total Revenue	25.41%	-0.13%	-2.92%	-0.49%	-1.29%	-2.59%	-15.98%	-12.03%	-13.87%	-12.07%	-11.01%	5.88%	-3.88%
63														
64	TOTAL CLASS A													
65	Demand Revenue	$687,098	($411,176)	($1,363,940)	($1,069,123)	($1,102,514)	($743,047)	$29,694	$920,699	$590,027	$739,711	$828,997	$1,153,030	$259,455
66	Base Energy Revenue	4,693,462	2,961,057	4,223,184	4,394,496	4,338,876	3,518,515	2,980,875	2,299,456	2,671,094	2,650,693	2,323,154	4,335,990	41,390,652
67	Percent Change in Base Rate Revenue	$5,380,561	$2,549,881	$2,859,244	$3,325,373	$3,236,361	$2,775,468	$3,010,570	$3,220,154	$3,261,122	$3,390,404	$3,152,151	$5,489,020	$41,650,307
68	FPPCA	(2,392,054)	(2,610,497)	(3,491,413)	(3,645,005)	(3,643,656)	(3,246,627)	(5,452,362)	(4,688,931)	(5,268,308)	(5,051,771)	(4,501,208)	(4,722,468)	(48,714,300)
69	Total Revenue Change	$2,988,507	($60,616)	($632,169)	($319,632)	($407,295)	($471,159)	($2,441,793)	($1,468,776)	($2,007,186)	($1,661,367)	($1,349,057)	$766,552	($7,063,993)
70	Percent Change in Base Rate Revenue	56.23%	23.08%	22.68%	26.50%	25.73%	23.86%	29.26%	36.65%	34.05%	36.63%	36.12%	63.98%	33.27%
71	Percent Change in Total Revenue	24.99%	-0.44%	-3.93%	-1.97%	-2.51%	-3.17%	-15.51%	-10.90%	-13.52%	-11.61%	-10.20%	5.76%	-4.06%

Arizona Electric Power Cooperative, Inc.

ANALYSIS OF REVENUE BY DETAILED CLASS WITH ACTUAL FPPCA - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	AVERAGE COST PER KWH - PRESENT REVENUES													
2	ANZA	$0.05637	$0.06167	$0.07043	$0.06508	$0.06478	$0.06915	$0.07405	$0.06939	$0.07581	$0.07685	$0.07420	$0.07080	$0.06904
3	DUNCAN	$0.06229	$0.07079	$0.06784	$0.06555	$0.06904	$0.07039	$0.07884	$0.06932	$0.07557	$0.07371	$0.07849	$0.07389	$0.07088
4	GRAHAM	$0.06260	$0.07200	$0.06784	$0.06859	$0.06687	$0.07051	$0.08126	$0.07421	$0.07324	$0.07437	$0.07804	$0.07347	$0.07129
5	MOHAVE	$0.05510	$0.05668	$0.05938	$0.05720	$0.05725	$0.05942	$0.07238	$0.07367	$0.07319	$0.07431	$0.07837	$0.07608	$0.06455
6	SULPHER	$0.05629	$0.05517	$0.05813	$0.05728	$0.05699	$0.05786	$0.07105	$0.07227	$0.07157	$0.07184	$0.07381	$0.07102	$0.06407
7	TRICO	$0.06314	$0.07128	$0.07115	$0.06657	$0.06761	$0.06959	$0.08189	$0.07946	$0.07459	$0.07407	$0.07661	$0.07251	$0.07189
8	AEPCO CLASS A	$0.05766	$0.06047	$0.06312	$0.06078	$0.06091	$0.06252	$0.07479	$0.07446	$0.07306	$0.07342	$0.07616	$0.07302	$0.06678
9														
10	AVERAGE COST PER KWH - PROPOSED REVENUES													
11	ANZA	$0.06929	$0.06555	$0.06466	$0.05814	$0.05844	$0.06242	$0.06650	$0.06789	$0.06015	$0.06422	$0.06551	$0.07193	$0.06415
12	DUNCAN	$0.07273	$0.06413	$0.05937	$0.05945	$0.05914	$0.06681	$0.07351	$0.07358	$0.06649	$0.06725	$0.07370	$0.07887	$0.06680
13	GRAHAM	$0.07525	$0.06841	$0.05914	$0.05782	$0.05791	$0.06430	$0.07216	$0.07523	$0.06916	$0.07206	$0.08050	$0.07745	$0.06744
14	MOHAVE	$0.07110	$0.05854	$0.05982	$0.05888	$0.05863	$0.05942	$0.06217	$0.06693	$0.06488	$0.06723	$0.07128	$0.08005	$0.06391
15	SULPHER	$0.07036	$0.05813	$0.05969	$0.05895	$0.05866	$0.05914	$0.06113	$0.06335	$0.06067	$0.06155	$0.06381	$0.07387	$0.06230
16	TRICO	$0.07597	$0.06344	$0.06287	$0.06168	$0.06154	$0.06247	$0.06487	$0.06728	$0.06327	$0.06511	$0.06910	$0.07945	$0.06564
17	AEPCO CLASS A	$0.07207	$0.06020	$0.06064	$0.05958	$0.05938	$0.06054	$0.06319	$0.06635	$0.06319	$0.06489	$0.06839	$0.07723	$0.06406

Arizona Electric Power Cooperative, Inc.

ANZA ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	6,468	6,132	9,936	11,832	10,716	9,036	5,592	6,564	9,156	7,440	7,596	6,408	96,876
3	kW - Current Year	5,712	7,488	10,608	10,404	9,948	9,684	6,852	5,388	8,860	8,093	7,071	6,304	96,412
4	kW - 12 Month Average	8,010	8,123	8,179	8,060	7,996	8,050	8,155	8,057	8,032	8,087	8,043	8,034	96,826
5	ARM Load Ratio Share	20.19%	20.31%	20.41%	20.15%	20.01%	19.97%	20.29%	20.12%	20.13%	20.26%	20.23%	20.16%	20.19%
6	KWH - TOTAL	3,733,956	3,974,280	4,547,868	5,266,380	5,087,034	4,309,788	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	4,047,215	51,283,408
7	KWH - BASE RESOURCES	3,516,089	3,974,280	4,058,041	5,070,048	4,966,884	4,304,383	3,861,588	3,682,884	4,682,804	4,126,590	3,963,021	3,076,659	49,283,270
8	KWH - OTHER EXISTING RESOURCES	217,867	0	489,827	196,332	104,947	0	0	0	0	0	0	970,556	1,979,530
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	15,203	5,405	0	0	0	0	0	0	20,608
10														
11	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - SYNCHRONIZATION	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$85,566	$112,170	$158,908	$155,852	$149,021	$145,066	$102,643	$80,712	$132,723	$121,233	$105,924	$94,434	$1,444,252
19	Base Energy Charge Revenue	77,405	82,387	94,277	109,172	105,454	89,342	80,051	76,346	97,075	85,544	82,153	83,899	1,063,105
20	Total Present Base Rate Revenue	$162,971	$194,557	$253,185	$265,024	$254,475	$234,408	$182,694	$157,058	$229,797	$206,777	$188,077	$178,333	$2,507,357
21	FPPCA	61,581	65,544	75,004	86,854	83,896	71,077	63,686	60,738	77,229	68,056	65,358	66,747	845,770
22	Total Present Revenue	$224,551	$260,101	$328,189	$351,878	$338,371	$305,486	$246,379	$217,797	$307,027	$274,833	$253,435	$245,080	$3,353,127
23														
24	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
25	Fixed Demand Charge	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	PPFAC	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
33	Fixed Demand Charge Revenue	$50,714	$51,009	$51,273	$50,623	$50,264	$50,163	$50,955	$50,527	$50,561	$50,893	$50,799	$50,644	$608,426
34	O&M Demand Charge Revenue	83,595	84,083	84,517	83,445	82,854	82,687	83,992	83,288	83,344	83,890	83,736	83,480	1,002,912
35	Base Resource Energy Revenue	110,960	125,420	128,063	160,000	156,744	135,837	121,863	116,224	147,779	130,226	125,064	97,093	1,555,271
36	Other Existing Resources Energy Revenue	13,442	0	30,221	12,113	6,475	0	0	0	0	0	0	59,880	122,130
37	Additional ARM Resources	0	0	0	0	938	333	0	0	0	0	0	0	1,271
38	Total Proposed Base Rate Revenue	$258,711	$260,512	$294,074	$306,180	$297,275	$269,021	$256,810	$250,039	$281,684	$265,008	$259,600	$291,097	$3,290,011
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$258,711	$260,512	$294,074	$306,180	$297,275	$269,021	$256,810	$250,039	$281,684	$265,008	$259,600	$291,097	$3,290,011
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$48,743	$22,922	($23,118)	($21,784)	($15,903)	($12,216)	$32,304	$53,103	$1,182	$13,549	$28,612	$39,690	$167,086
44	Change in Base Energy Charge Revenue	46,997	43,033	64,006	62,940	58,703	46,828	41,812	39,878	50,704	44,682	42,911	73,074	615,568
45	Change in Base Rate Revenue	$95,740	$65,955	$40,889	$41,156	$42,800	$34,613	$74,117	$92,981	$51,867	$58,231	$71,523	$112,764	$782,654
46	Change in FPPCA Revenue	(61,581)	(65,544)	(75,004)	(86,854)	(83,896)	(71,077)	(63,686)	(60,738)	(77,229)	(68,056)	(65,358)	(66,747)	(845,770)
47	Change in Total Revenue	$34,159	$410	($34,115)	($45,698)	($41,096)	($36,465)	$10,431	$32,242	($25,343)	($9,825)	$6,165	$46,017	($63,117)
48	Percentage Change in Base Rate Revenue	58.75%	33.90%	16.15%	15.53%	16.82%	14.77%	40.57%	59.20%	22.58%	28.16%	38.03%	63.23%	31.21%
49	Percentage Change in Total Revenue	15.21%	0.16%	-10.39%	-12.99%	-12.15%	-11.94%	4.23%	14.80%	-8.25%	-3.57%	2.43%	18.78%	-1.88%

ARM kW Demand Total (Excluding Trico)	39,671	39,997	40,066	39,990	39,956	40,307	40,198	40,051	39,901	39,910	39,767	39,846	479,660

Arizona Electric Power Cooperative, Inc.

DUNCAN ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	3,100	5,640	6,660	6,020	6,520	3,720	4,520	3,320	4,520	4,320	4,180	3,260	55,780
3	kW - Current Year	3,860	6,040	6,960	5,940	6,620	5,360	4,020	2,780	4,300	3,900	3,900	3,500	57,180
4	kW - 12 Month Average	4,712	4,745	4,770	4,763	4,772	4,908	4,867	4,822	4,803	4,768	4,745	4,765	57,440
5	ARM Load Ratio Share	11.88%	11.86%	11.91%	11.91%	11.94%	12.18%	12.11%	12.04%	12.04%	11.95%	11.93%	11.96%	11.98%
6	KWH - TOTAL	2,004,660	2,422,840	3,223,350	2,960,420	2,955,880	2,300,600	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,984,450	28,079,760
7	KWH - BASE RESOURCES	1,887,693	2,422,840	2,876,180	2,850,055	2,886,066	2,297,715	1,919,560	1,905,850	2,292,120	2,226,640	1,883,390	1,508,562	26,956,670
8	KWH - OTHER EXISTING RESOURCES	116,967	0	347,170	110,365	60,981	0	0	0	0	0	0	475,888	1,111,371
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	8,834	2,885	0	0	0	0	0	0	11,719
10														
11	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$57,823	$90,479	$104,261	$88,981	$99,168	$80,293	$60,220	$41,644	$64,414	$58,422	$58,422	$52,430	$856,556
19	Base Energy Charge Revenue	41,557	50,225	66,820	61,370	61,275	47,691	39,792	39,508	47,516	46,158	39,043	41,138	582,093
20	Total Present Base Rate Revenue	$99,379	$140,705	$171,081	$150,351	$160,443	$127,984	$100,012	$81,153	$111,930	$104,580	$97,465	$93,568	$1,438,650
21	FPPCA	33,061	39,958	53,160	48,824	48,749	37,942	31,658	31,431	37,802	36,722	31,061	32,728	463,094
22	Total Present Revenue	$132,440	$180,662	$224,241	$199,174	$209,192	$165,926	$131,670	$112,584	$149,731	$141,302	$128,526	$126,295	$1,901,744
23														
24	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
25	Fixed Demand Charge	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
33	Fixed Demand Charge Revenue	$29,831	$29,797	$29,903	$29,917	$29,995	$30,586	$30,408	$30,238	$30,236	$30,009	$29,969	$30,036	$360,925
34	O&M Demand Charge Revenue	49,173	49,116	49,290	49,315	49,444	50,417	50,124	49,843	49,840	49,465	49,401	49,510	594,939
35	Base Resource Energy Revenue	59,571	76,459	90,766	89,941	91,078	72,511	60,577	60,144	72,334	70,268	59,436	47,607	850,693
36	Other Existing Resources Energy Revenu	7,216	0	21,419	6,809	3,762	0	0	0	0	0	0	29,361	68,568
37	Additional ARM Resources	0	0	0	0	545	178	0	0	0	0	0	0	723
38	Total Proposed Base Rate Revenue	$145,792	$155,373	$191,378	$175,982	$174,824	$153,692	$141,110	$140,226	$152,409	$149,742	$138,806	$156,514	$1,875,847
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$145,792	$155,373	$191,378	$175,982	$174,824	$153,692	$141,110	$140,226	$152,409	$149,742	$138,806	$156,514	$1,875,847
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$21,181	($11,566)	($25,068)	($9,749)	($19,728)	$710	$20,313	$38,437	$15,661	$21,052	$20,948	$27,116	$99,307
44	Change in Base Energy Charge Revenue	25,231	26,234	45,365	35,381	34,110	24,997	20,785	20,636	24,819	24,110	20,393	35,830	337,890
45	Change in Base Rate Revenue	$46,412	$14,668	$20,297	$25,632	$14,381	$25,708	$41,098	$59,073	$40,480	$45,162	$41,341	$62,946	$437,197
46	Change in FPPCA Revenue	(33,061)	(39,958)	(53,160)	(48,824)	(48,749)	(37,942)	(31,658)	(31,431)	(37,802)	(36,722)	(31,061)	(32,728)	(463,094)
47	Change in Total Revenue	$13,351	($25,290)	($32,863)	($23,192)	($34,367)	($12,234)	$9,440	$27,641	$2,678	$8,440	$10,280	$30,218	($25,897)
48	Percentage Change in Base Rate Revenu	46.70%	10.42%	11.86%	17.05%	8.96%	20.09%	41.09%	72.79%	36.17%	43.18%	42.42%	67.27%	30.39%
49	Percentage Change in Total Revenue	10.08%	-14.00%	-14.66%	-11.64%	-16.43%	-7.37%	7.17%	24.55%	1.79%	5.97%	8.00%	23.93%	-1.36%

Arizona Electric Power Cooperative, Inc.

GRAHAM ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	21,235	29,349	40,099	39,126	36,733	30,341	27,052	18,498	21,918	20,119	19,731	19,458	323,658
3	kW - Current Year	20,966	31,511	39,951	39,726	36,986	32,263	24,988	18,448	20,642	19,992	18,818	20,271	324,562
4	kW - 12 Month Average	26,949	27,129	27,117	27,167	27,188	27,348	27,176	27,172	27,066	27,055	26,979	27,047	325,394
5	ARM Load Ratio Share	67.93%	67.83%	67.68%	67.93%	68.05%	67.85%	67.61%	67.84%	67.83%	67.79%	67.84%	67.88%	67.84%
6	KWH - TOTAL	10,775,112	12,244,130	18,499,166	17,976,098	17,655,323	13,801,595	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	11,677,543	156,396,015
7	KWH - BASE RESOURCES	10,146,411	12,244,130	16,506,717	17,305,943	17,238,326	13,784,286	11,076,763	10,334,556	12,000,020	11,134,378	9,221,331	8,877,170	149,870,030
8	KWH - OTHER EXISTING RESOURCES	628,701	0	1,992,449	670,155	364,234	(0)	0	0	0	0	0	2,800,373	6,455,912
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	52,763	17,309	0	0	0	0	0	0	70,073
10														
11	**PRESENT RATES**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$314,071	$472,035	$598,466	$595,095	$554,050	$483,300	$374,320	$276,351	$309,217	$299,480	$281,894	$303,660	$4,861,939
19	Base Energy Charge Revenue	223,368	253,821	383,488	372,645	365,995	286,107	229,621	214,235	248,760	230,816	191,158	242,075	3,242,089
20	Total Present Base Rate Revenue	$537,439	$725,856	$981,954	$967,740	$920,045	$769,407	$603,942	$490,586	$557,978	$530,296	$473,052	$545,735	$8,104,028
21	FPPCA	177,704	201,931	305,090	296,463	291,173	227,617	182,679	170,438	197,905	183,629	152,079	192,587	2,579,296
22	Total Present Revenue	$715,143	$927,787	$1,287,044	$1,264,203	$1,211,218	$997,024	$786,620	$661,025	$755,883	$713,925	$625,131	$738,322	$10,683,325
23														
24	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
25	Fixed Demand Charge	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	$251,168	
26	O&M Demand Charge	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	$414,019	
27	Base Resource Energy Charge	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	$0.03156	
28	Other Existing Resources Energy Charge	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
29	Additional ARM Resources	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	$0.06170	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
33	Fixed Demand Charge Revenue	$170,623	$170,362	$169,992	$170,628	$170,909	$170,419	$169,805	$170,403	$170,371	$170,267	$170,399	$170,488	$2,044,667
34	O&M Demand Charge Revenue	281,251	280,820	280,211	281,259	281,721	280,914	279,902	280,887	280,835	280,663	280,882	281,028	3,370,373
35	Base Resource Energy Revenue	320,198	386,398	520,916	546,137	544,003	435,002	349,558	326,136	378,694	351,376	291,005	280,144	4,729,567
36	Other Existing Resources Energy Revenue	38,789	0	122,927	41,346	22,472	(0)	0	0	0	0	0	172,773	398,307
37	Additional ARM Resources	0	0	0	0	3,255	1,068	0	0	0	0	0	0	4,323
38	Total Proposed Base Rate Revenue	$810,861	$837,579	$1,094,046	$1,039,371	$1,022,360	$887,403	$799,265	$777,426	$829,901	$802,307	$742,286	$904,433	$10,547,237
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$810,861	$837,579	$1,094,046	$1,039,371	$1,022,360	$887,403	$799,265	$777,426	$829,901	$802,307	$742,286	$904,433	$10,547,237
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$137,803	($20,853)	($148,263)	($143,208)	($101,421)	($31,967)	$75,367	$174,939	$141,989	$151,450	$169,387	$147,857	$553,101
44	Change in Base Energy Charge Revenue	135,619	132,577	260,355	214,839	203,736	149,962	119,937	111,900	129,934	120,561	99,847	210,842	1,890,108
45	Change in Base Rate Revenue	$273,422	$111,724	$112,092	$71,631	$102,315	$117,996	$195,324	$286,840	$271,923	$272,011	$269,234	$358,698	$2,443,209
46	Change in FPPCA Revenue	(177,704)	(201,931)	(305,090)	(296,463)	(291,173)	(227,617)	(182,679)	(170,438)	(197,905)	(183,629)	(152,079)	(192,587)	(2,579,296)
47	Change in Total Revenue	$95,718	($90,208)	($192,997)	($224,832)	($188,858)	($109,621)	$12,645	$116,401	$74,018	$88,382	$117,155	$166,111	($136,087)
48	Percentage Change in Base Rate Revenue	50.88%	15.39%	11.42%	7.40%	11.12%	15.34%	32.34%	58.47%	48.73%	51.29%	56.91%	65.73%	30.15%
49	Percentage Change in Total Revenue	13.38%	-9.72%	-15.00%	-17.78%	-15.59%	-10.99%	1.61%	17.61%	9.79%	12.38%	18.74%	22.50%	-1.27%

Arizona Electric Power Cooperative, Inc.

MOHAVE ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	$0.015224	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$855,113	$855,113	$855,113	$855,113	$855,113	$841,539	$855,113	$855,113	$855,113	$841,248	$855,113	$841,405	$10,220,208
7														
8	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
9	KW	132,188	164,074	180,771	180,854	180,702	177,704	147,539	108,949	119,116	115,595	116,233	99,674	1,723,399
10	KWH - BASE RESOURCES	50,755,139	78,652,286	76,386,367	80,696,904	81,266,866	76,916,303	68,973,762	58,722,347	62,483,136	58,217,551	52,072,523	39,557,362	784,700,545
11	KWH - OTHER EXISTING RESOURCES	27,052,061	3,516,954	8,279,463	11,890,766	11,057,374	6,217,897	4,712,478	1,285,853	1,329,104	1,653,049	800,277	12,884,238	90,679,515
12	Demand Revenue	$1,814,798	$2,046,290	$2,167,510	$2,168,113	$2,167,010	$2,131,670	$1,926,246	$1,646,083	$1,719,895	$1,680,468	$1,698,967	$1,565,038	$22,732,087
13	Base Energy Charge Revenue	1,612,943	1,703,368	1,755,123	1,919,342	1,913,881	1,723,372	1,527,516	1,243,970	1,322,828	1,241,118	1,096,053	1,087,114	18,146,629
14	Total Present Base Rate Revenue	$3,427,741	$3,749,659	$3,922,633	$4,087,455	$4,080,891	$3,855,042	$3,453,762	$2,890,053	$3,042,723	$2,921,585	$2,795,020	$2,652,152	$40,878,716
15	FPPCA	1,184,537	1,250,945	1,288,953	1,409,555	1,405,545	1,265,635	1,121,800	913,565	971,478	911,470	804,936	798,371	13,326,790
16	Total Present Revenue	$4,612,278	$5,000,603	$5,211,586	$5,497,011	$5,486,436	$5,120,677	$4,575,562	$3,803,618	$4,014,201	$3,833,055	$3,599,956	$3,450,523	$54,205,506
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	
20	O&M Demand Charge	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	$1,274,882	
21	Base Resource Energy Charge	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	$0.03215	
22	Other Existing Resources Energy Charge	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	$0.06879	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$764,975	$9,179,703
27	O&M Demand Charge Revenue	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	1,274,882	15,298,589
28	Base Resource Energy Revenue	1,631,645	2,528,466	2,455,622	2,594,195	2,612,518	2,472,658	2,217,326	1,887,770	2,008,670	1,871,542	1,673,996	1,271,666	25,226,075
29	Other Existing Resources Energy Revenue	1,860,829	241,921	569,519	817,930	760,603	427,710	324,157	88,450	91,425	113,708	55,049	886,267	6,237,567
30	Total Proposed Base Rate Revenue	$5,532,332	$4,810,244	$5,064,999	$5,451,982	$5,412,978	$4,940,226	$4,581,341	$4,016,078	$4,139,952	$4,025,108	$3,768,902	$4,197,791	$55,941,934
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$5,532,332	$4,810,244	$5,064,999	$5,451,982	$5,412,978	$4,940,226	$4,581,341	$4,016,078	$4,139,952	$4,025,108	$3,768,902	$4,197,791	$55,941,934
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$225,060	($6,433)	($127,653)	($128,255)	($127,152)	($91,812)	$113,612	$393,775	$319,962	$359,390	$340,891	$474,820	$1,746,204
36	Change in Energy Charge Revenue	1,879,531	1,067,018	1,270,019	1,492,782	1,459,239	1,176,997	1,013,968	732,250	777,267	744,133	632,991	1,070,819	13,317,014
37	Change in Base Rate Revenue	$2,104,591	$1,060,585	$1,142,366	$1,364,527	$1,332,087	$1,085,184	$1,127,579	$1,126,025	$1,097,230	$1,103,523	$973,882	$1,545,639	$15,063,218
38	Change in FPPCA Revenue	(1,184,537)	(1,250,945)	(1,288,953)	(1,409,555)	(1,405,545)	(1,265,635)	(1,121,800)	(913,565)	(971,478)	(911,470)	(804,936)	(798,371)	(13,326,790)
39	Change in Total Revenue	$920,053	($190,359)	($146,587)	($45,028)	($73,457)	($180,451)	$5,780	$212,460	$125,752	$192,053	$168,946	$747,268	$1,736,428
40	Percentage Change in Base Rate Revenue	61.40%	28.28%	29.12%	33.38%	32.64%	28.15%	32.65%	38.96%	36.06%	37.77%	34.84%	58.28%	36.85%
41	Percentage Change in Total Revenue	19.95%	-3.81%	-2.81%	-0.82%	-1.34%	-3.52%	0.13%	5.59%	3.13%	5.01%	4.69%	21.66%	3.20%

Arizona Electric Power Cooperative, Inc.

SULPHUR SPRINGS ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**PRESENT RATES**													
2	Energy & FPPCA RATES													
3	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
4	FPPCA - PARTIAL	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	$0.015992	
5	Demand Charge - Partial	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
6	Fixed Charge	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$757,429	$9,089,148
7														
8	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
9	KW	131,134	137,934	147,034	139,734	137,734	135,934	132,134	118,334	141,534	140,700	136,700	128,900	1,629,806
10	KWH - BASE RESOURCES	45,109,060	71,215,789	67,765,404	69,476,926	70,187,865	68,400,037	63,695,444	58,536,258	64,833,044	62,900,309	57,866,673	36,296,091	738,282,902
11	KWH - OTHER EXISTING RESOURCES	24,649,540	3,978,331	7,193,196	5,914,194	5,523,255	4,035,563	5,507,676	3,567,342	5,625,076	6,595,091	6,141,527	30,024,309	108,755,098
12	Demand Revenue	$1,709,462	$1,758,830	$1,824,896	$1,771,898	$1,757,378	$1,744,310	$1,716,722	$1,616,534	$1,784,966	$1,778,911	$1,764,391	$1,693,243	$20,921,540
13	Base Energy Charge Revenue	1,446,096	1,558,774	1,553,892	1,562,858	1,569,492	1,501,590	1,434,581	1,287,408	1,460,597	1,440,640	1,326,890	1,416,282	17,559,098
14	Total Present Base Rate Revenue	$3,155,558	$3,317,604	$3,378,788	$3,334,756	$3,326,869	$3,245,900	$3,151,303	$2,903,941	$3,245,563	$3,219,551	$3,091,281	$3,109,525	$38,480,637
15	FPPCA	1,115,571	1,202,495	1,198,729	1,205,646	1,210,763	1,158,381	1,106,688	993,153	1,126,758	1,111,362	1,023,611	1,092,571	13,545,728
16	Total Present Revenue	$4,271,129	$4,520,099	$4,577,516	$4,540,401	$4,537,632	$4,404,281	$4,257,990	$3,897,095	$4,372,320	$4,330,913	$4,114,892	$4,202,096	$52,026,365
17														
18	**PROPOSED RATES**													
19	Fixed Demand Charge	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	
20	O&M Demand Charge	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	$1,128,876	
21	Base Resource Energy Charge	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	$0.03229	
22	Other Existing Resources Energy Charge	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	$0.06676	
23	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
24														
25	**PROPOSED REVENUES**													
26	Fixed Demand Charge Revenue	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$677,366	$8,128,396
27	O&M Demand Charge Revenue	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	1,128,876	13,546,516
28	Base Resource Energy Revenue	1,456,357	2,299,219	2,187,822	2,243,079	2,266,032	2,208,312	2,056,423	1,889,857	2,093,151	2,030,752	1,868,240	1,236,399	23,835,642
29	Other Existing Resources Energy Revenue	1,645,489	265,575	480,184	394,804	368,707	269,395	367,667	238,139	375,504	440,258	409,980	2,004,284	7,259,986
30	Total Proposed Base Rate Revenue	$4,908,089	$4,371,037	$4,474,250	$4,444,126	$4,440,982	$4,283,950	$4,230,332	$3,934,239	$4,274,897	$4,277,252	$4,084,462	$5,046,925	$52,770,540
31	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Proposed Revenue	$4,908,089	$4,371,037	$4,474,250	$4,444,126	$4,440,982	$4,283,950	$4,230,332	$3,934,239	$4,274,897	$4,277,252	$4,084,462	$5,046,925	$52,770,540
33														
34	**PROPOSED REVENUE CHANGES**													
35	Change in Fixed and Demand Revenue	$96,781	$47,413	($18,653)	$34,345	$48,865	$61,933	$89,521	$189,709	$21,277	$27,332	$41,852	$113,000	$753,372
36	Change in Energy Charge Revenue	1,655,750	1,006,020	1,114,115	1,075,026	1,065,248	976,117	989,509	840,589	1,008,058	1,030,370	951,329	1,824,400	13,536,530
37	Change in Base Rate Revenue	$1,752,531	$1,053,433	$1,095,462	$1,109,370	$1,114,112	$1,038,050	$1,079,030	$1,030,298	$1,029,335	$1,057,701	$993,161	$1,937,400	$14,289,903
38	Change in FPPCA Revenue	(1,115,571)	(1,202,495)	(1,198,729)	(1,205,646)	(1,210,763)	(1,158,381)	(1,106,688)	(993,153)	(1,126,758)	(1,111,362)	(1,023,611)	(1,092,571)	(13,545,728)
39	Change in Total Revenue	$636,960	($149,063)	($103,267)	($96,275)	($96,651)	($120,331)	($27,658)	$37,144	($97,423)	($53,661)	($30,430)	$844,828	$744,175
40	Percentage Change in Base Rate Revenue	55.54%	31.75%	32.42%	33.27%	33.49%	31.98%	34.24%	35.48%	31.72%	32.85%	32.13%	62.31%	37.14%
41	Percentage Change in Total Revenue	14.91%	-3.30%	-2.26%	-2.12%	-2.13%	-2.73%	-0.65%	0.95%	-2.23%	-1.24%	-0.74%	20.10%	1.43%

Arizona Electric Power Cooperative, Inc.

TRICO ADJUSTED PRESENT WITH SYCHCRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	**BILLING DETERMINANTS**													
2	kW - Previous Year	88,830	110,939	146,640	163,888	146,704	139,833	110,067	87,080	92,923	87,572	84,462	69,545	1,328,483
3	kW - Current Year	85,906	125,972	164,592	149,858	155,646	141,128	116,545	91,700	90,417	85,278	81,248	73,021	1,361,311
4	kW - 12 Month Moving Average	110,463	111,716	113,212	112,043	112,788	112,896	113,436	113,821	113,612	113,421	113,153	113,443	1,354,003
5	ARM Load Ratio Share	73.58%	73.64%	73.86%	73.70%	73.84%	73.69%	73.84%	73.97%	74.01%	73.97%	73.99%	74.01%	73.84%
6	KWH - TOTAL	43,348,839	49,883,272	69,143,826	72,230,849	72,594,073	62,002,723	50,728,275	42,934,549	49,950,664	48,018,911	41,759,997	43,690,558	646,286,536
7	KWH - BASE RESOURCES	30,122,267	46,767,098	49,428,600	52,271,075	52,631,923	49,492,013	44,675,503	41,333,563	47,031,999	44,237,586	39,114,179	25,511,101	522,616,908
8	KWH - OTHER EXISTING RESOURCES	13,226,572	3,116,174	19,715,226	19,959,774	17,638,950	11,736,310	6,052,772	1,600,986	2,918,665	3,781,325	2,645,818	18,179,457	120,572,028
9	KWH - ADDITIONAL ARM RESOURCES	0	0	0	0	2,323,200	774,400	0	0	0	0	0	0	3,097,600
10														
11	**PRESENT RATES w/ FPPCA SYNCHRONIZED**													
12	Energy & FPPCA RATES													
13	Base Energy	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730	
14	FPPCA - FULL	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	$0.016492	
15	Demand Charge - Full	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	$14.98	
16														
17	**PRESENT REVENUES**													
18	Demand Revenue	$1,286,872	$1,887,061	$2,465,588	$2,244,873	$2,331,577	$2,114,097	$1,745,844	$1,373,666	$1,354,447	$1,277,464	$1,217,095	$1,093,855	$20,392,439
19	Base Energy Charge Revenue	898,621	1,034,080	1,433,352	1,497,345	1,504,875	1,285,316	1,051,597	890,033	1,035,477	995,432	865,685	905,705	13,397,520
20	Total Present Base Rate Revenue	$2,185,493	$2,921,141	$3,898,940	$3,742,218	$3,836,452	$3,399,414	$2,797,441	$2,263,699	$2,389,924	$2,272,896	$2,082,780	$1,999,560	$33,789,959
21	FPPCA	714,913	822,679	1,140,326	1,191,237	1,197,228	1,022,554	836,615	708,080	823,791	791,932	688,709	720,548	10,658,613
22	Total Present Revenue	$2,900,406	$3,743,820	$5,039,266	$4,933,456	$5,033,680	$4,421,968	$3,634,056	$2,971,779	$3,213,715	$3,064,828	$2,771,489	$2,720,108	$44,448,572
23														
24	**PROPOSED RATES - Monthly Fixed and O&M Facility Charge**													
25	Fixed Demand Charge	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	
26	O&M Demand Charge	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	$764,465	
27	Base Resource Energy Charge	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	$0.03238	
28	Other Existing Resources Energy Charge	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	
29	Additional ARM Resources	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	$0.06604	
30	FPPCA	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
31														
32	**PROPOSED REVENUES - Monthly Fixed and O&M Facility Charge**													
33	Fixed Demand Charge Revenue	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$679,937	$8,159,241
34	O&M Demand Charge Revenue	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	764,465	9,173,582
35	Base Resource Energy Revenue	975,449	1,514,458	1,600,645	1,692,693	1,704,378	1,602,698	1,446,726	1,338,504	1,523,036	1,432,544	1,266,633	826,125	16,923,888
36	Other Existing Resources Energy Revenue	873,507	205,798	1,302,030	1,318,181	1,164,909	775,088	399,736	105,732	192,754	249,726	174,735	1,200,605	7,962,802
37	Additional ARM Resources	0	0	0	0	153,428	51,143	0	0	0	0	0	0	204,571
38	Total Proposed Base Rate Revenue	$3,293,358	$3,164,657	$4,347,077	$4,455,275	$4,467,118	$3,873,331	$3,290,864	$2,888,638	$3,160,192	$3,126,672	$2,885,770	$3,471,132	$42,424,084
39	FPPCA Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Proposed Revenue	$3,293,358	$3,164,657	$4,347,077	$4,455,275	$4,467,118	$3,873,331	$3,290,864	$2,888,638	$3,160,192	$3,126,672	$2,885,770	$3,471,132	$42,424,084
41														
42	**PROPOSED REVENUE CHANGES**													
43	Change in Fixed and Demand Revenue	$157,530	($442,659)	($1,021,186)	($800,471)	($887,175)	($669,696)	($301,442)	$70,736	$89,955	$166,937	$227,307	$350,547	($3,059,616)
44	Change in Base Energy Charge Revenue	950,335	686,175	1,469,324	1,513,528	1,517,841	1,143,613	794,865	554,202	680,313	686,838	575,683	1,121,025	11,693,741
45	Change in Base Rate Revenue	$1,107,865	$243,517	$448,137	$713,057	$630,665	$473,917	$493,423	$624,938	$770,268	$853,776	$802,990	$1,471,573	$8,634,126
46	Change in FPPCA Revenue	(714,913)	(822,679)	(1,140,326)	(1,191,237)	(1,197,228)	(1,022,554)	(836,615)	(708,080)	(823,791)	(791,932)	(688,709)	(720,548)	(10,658,613)
47	Change in Total Revenue	$392,952	($579,163)	($692,188)	($478,180)	($566,562)	($548,637)	($343,193)	($83,142)	($53,523)	$61,844	$114,281	$751,024	($2,024,487)
48	Percentage Change in Base Rate Revenue	50.69%	8.34%	11.49%	19.05%	16.44%	13.94%	17.64%	27.61%	32.23%	37.56%	38.55%	73.59%	25.55%
49	Percentage Change in Total Revenue	13.55%	-15.47%	-13.74%	-9.69%	-11.26%	-12.41%	-9.44%	-2.80%	-1.67%	2.02%	4.12%	27.61%	-4.55%

Arizona Electric Power Cooperative, Inc.

CLASS A MEMBER ADJUSTED PRESENT WITH SYNCHRONIZED FPPCA AND PROPOSED REVENUES - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	PRESENT REVENUES w/ FPPAC SYNCHRONIZED													
2	FULL REQUIREMENTS													
3	Demand Revenue	$457,459	$674,684	$861,635	$839,929	$802,239	$706,659	$537,183	$398,708	$506,354	$479,135	$446,239	$450,524	$7,162,747
4	Base Energy Revenue	342,330	386,433	544,585	543,186	532,724	423,140	349,464	330,090	393,351	362,518	312,354	367,112	4,887,288
5	Total Present Base Rate Revenue	$799,789	$1,061,117	$1,406,220	$1,383,115	$1,334,963	$1,131,799	$886,647	$728,797	$899,705	$841,653	$758,594	$817,635	$12,050,035
6	FPPCA	272,346	307,433	433,253	432,140	423,818	336,636	278,022	262,608	312,936	288,407	248,498	292,062	3,888,161
7	Total Adjusted Present Revenue	$1,072,135	$1,368,550	$1,839,473	$1,815,255	$1,758,781	$1,468,435	$1,164,669	$991,406	$1,212,641	$1,130,061	$1,007,092	$1,109,697	$15,938,195
8														
9	PARTIAL REQUIREMENTS													
10	Fixed / O&M Charge Revenue	$4,811,132	$5,692,181	$6,457,994	$6,184,864	$6,255,964	$5,990,077	$5,388,812	$4,636,283	$4,859,308	$4,736,843	$4,680,453	$4,352,135	$64,046,066
11	Base Energy Revenue	3,957,660	4,296,223	4,742,366	4,979,546	4,988,248	4,510,278	4,013,694	3,421,411	3,818,902	3,677,189	3,288,628	3,409,102	49,103,246
12	Total Present Base Rate Revenue	$8,768,792	$9,988,403	$11,200,360	$11,164,430	$11,244,213	$10,500,356	$9,402,506	$8,057,693	$8,678,209	$8,414,032	$7,969,081	$7,761,237	$113,149,312
13	FPPCA	3,015,021	3,276,119	3,628,008	3,806,438	3,813,535	3,446,571	3,065,103	2,614,799	2,922,026	2,814,764	2,517,256	2,611,491	37,531,131
14	Total Adjusted Present Revenue	$11,783,813	$13,264,523	$14,828,368	$14,970,868	$15,057,748	$13,946,926	$12,467,608	$10,672,492	$11,600,236	$11,228,797	$10,486,337	$10,372,728	$150,680,443
15														
16	TOTAL CLASS A													
17	Demand Revenue	$5,268,591	$6,366,865	$7,319,629	$7,024,812	$7,058,203	$6,698,736	$5,925,995	$5,034,990	$5,365,662	$5,215,978	$5,126,692	$4,802,659	$71,208,813
18	Base Energy Revenue	4,299,990	4,682,656	5,286,951	5,522,732	5,520,973	4,933,419	4,363,158	3,751,501	4,212,252	4,039,707	3,600,982	3,776,213	53,990,534
19	Total Present Base Rate Revenue	$9,568,581	$11,049,521	$12,606,580	$12,547,544	$12,579,176	$11,632,155	$10,289,153	$8,786,491	$9,577,914	$9,255,686	$8,727,674	$8,578,872	$125,199,347
20	FPPCA	3,287,367	3,583,552	4,061,261	4,238,578	4,237,353	3,783,207	3,343,125	2,877,407	3,234,962	3,103,171	2,765,755	2,903,553	41,419,292
21	Total Adjusted Present Revenue	$12,855,948	$14,633,073	$16,667,841	$16,786,123	$16,816,529	$15,415,362	$13,632,278	$11,663,898	$12,812,877	$12,358,857	$11,493,429	$11,482,425	$166,618,638
22														
23	PROPOSED REVENUES													
24	FULL REQUIREMENTS													
25	Demand Revenue	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$665,187	$7,982,241
26	Base Energy Revenue	550,177	588,277	914,311	856,347	829,273	644,929	531,998	502,504	598,807	551,870	475,505	686,857	7,730,854
27	Total Proposed Base Rate Revenue	$1,215,363	$1,253,463	$1,579,498	$1,521,533	$1,494,459	$1,310,115	$1,197,185	$1,167,691	$1,263,994	$1,217,057	$1,140,691	$1,352,044	$15,713,095
28	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total Adjusted Proposed Revenue	$1,215,363	$1,253,463	$1,579,498	$1,521,533	$1,494,459	$1,310,115	$1,197,185	$1,167,691	$1,263,994	$1,217,057	$1,140,691	$1,352,044	$15,713,095
30														
31	PARTIAL REQUIREMENTS													
32	Fixed / O&M Charge Revenue	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$5,290,502	$63,486,027
33	Base Energy Revenue	8,443,276	7,055,436	8,595,823	9,060,881	9,030,576	7,807,005	6,812,035	5,548,452	6,284,539	6,138,530	5,448,632	7,425,346	87,650,532
34	Total Proposed Base Rate Revenue	$13,733,778	$12,345,938	$13,886,326	$14,351,384	$14,321,078	$13,097,507	$12,102,537	$10,838,955	$11,575,041	$11,429,032	$10,739,134	$12,715,848	$151,136,559
35	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total Adjusted Proposed Revenue	$13,733,778	$12,345,938	$13,886,326	$14,351,384	$14,321,078	$13,097,507	$12,102,537	$10,838,955	$11,575,041	$11,429,032	$10,739,134	$12,715,848	$151,136,559
37														
38	TOTAL CLASS A													
39	Demand Revenue	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$5,955,689	$71,468,267
40	Base Energy Revenue	8,993,452	7,643,712	9,510,135	9,917,228	9,859,848	8,451,934	7,344,034	6,050,956	6,883,347	6,690,400	5,924,137	8,112,203	95,381,386
41	Total Proposed Base Rate Revenue	$14,949,141	$13,599,401	$15,465,824	$15,872,917	$15,815,537	$14,407,622	$13,299,722	$12,006,645	$12,839,036	$12,646,089	$11,879,826	$14,067,892	$166,849,654
42	FPPCA	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Adjusted Proposed Revenue	$14,949,141	$13,599,401	$15,465,824	$15,872,917	$15,815,537	$14,407,622	$13,299,722	$12,006,645	$12,839,036	$12,646,089	$11,879,826	$14,067,892	$166,849,654
44														
45	PROPOSED REVENUE CHANGES													
46	FULL REQUIREMENTS													
47	Demand Revenue	$207,727	($9,497)	($196,448)	($174,742)	($137,052)	($43,472)	$128,004	$266,479	$158,833	$186,051	$218,948	$214,663	$819,494
48	Base Energy Revenue	207,847	201,844	369,726	313,161	296,548	221,788	182,534	172,414	205,457	189,352	163,150	319,745	2,843,566
49	Change in Base Rate Revenue	$415,574	$192,346	$173,278	$138,419	$159,496	$178,316	$310,538	$438,893	$364,290	$375,404	$382,098	$534,409	$3,663,060
50	FPPCA	(272,346)	(307,433)	(433,253)	(432,140)	(423,818)	(336,636)	(278,022)	(262,608)	(312,936)	(288,407)	(248,498)	(292,062)	(3,888,161)
51	Total Revenue Change	$143,229	($115,087)	($259,975)	($293,722)	($264,322)	($158,320)	$32,516	$176,285	$51,353	$86,996	$133,599	$242,347	($225,100)
52	Percent Change in Base Rate Revenue	4.74%	1.93%	1.55%	1.24%	1.42%	1.70%	3.30%	5.45%	4.20%	4.46%	4.79%	6.89%	3.24%
53	Percent Change in Total Revenue	13.36%	-8.41%	-14.13%	-16.18%	-15.03%	-10.78%	2.79%	17.78%	4.23%	7.70%	13.27%	21.84%	-1.41%
54														
55	PARTIAL REQUIREMENTS													
56	Fixed / O&M Charge Revenue	$479,371	($401,678)	($1,167,492)	($894,381)	($965,462)	($699,575)	($98,310)	$654,220	$431,195	$553,659	$610,049	$938,367	($560,039)
57	Base Energy Revenue	4,485,615	2,759,213	3,853,458	4,081,336	4,042,327	3,296,726	2,798,342	2,127,042	2,465,637	2,461,341	2,160,004	4,016,245	38,547,286
58	Change in Base Rate Revenue	$4,964,986	$2,357,535	$2,685,965	$3,186,954	$3,076,865	$2,597,152	$2,700,032	$2,781,261	$2,896,832	$3,015,000	$2,770,053	$4,954,611	$37,987,247
59	FPPCA	(3,015,021)	(3,276,119)	(3,628,008)	(3,806,438)	(3,813,535)	(3,446,571)	(3,065,103)	(2,614,799)	(2,922,026)	(2,814,764)	(2,517,256)	(2,611,491)	(37,531,131)
60	Total Revenue Change	$1,949,965	($918,585)	($942,042)	($619,484)	($736,670)	($849,419)	($365,071)	$166,463	($25,194)	$200,236	$252,797	$2,343,120	$456,116
61	Percent Change in Base Rate Revenue	56.82%	23.60%	23.98%	28.55%	27.36%	24.73%	28.72%	34.52%	33.38%	35.83%	34.76%	63.84%	33.57%
62	Percent Change in Total Revenue	16.55%	-6.93%	-6.35%	-4.14%	-4.89%	-6.09%	-2.93%	1.56%	-0.22%	1.78%	2.41%	22.59%	0.30%
63														
64	TOTAL CLASS A													
65	Demand Revenue	$687,098	($411,176)	($1,363,940)	($1,069,123)	($1,102,514)	($743,047)	$29,694	$920,699	$590,027	$739,711	$828,997	$1,153,030	$259,455
66	Base Energy Revenue	4,693,462	2,961,057	4,223,184	4,394,496	4,338,876	3,518,515	2,980,875	2,299,456	2,671,094	2,650,693	2,323,154	4,335,990	41,390,652
67	Percent Change in Base Rate Revenue	$5,380,561	$2,549,881	$2,859,244	$3,325,373	$3,236,361	$2,775,468	$3,010,570	$3,220,154	$3,261,122	$3,390,404	$3,152,151	$5,489,020	$41,650,307
68	FPPCA	(3,287,367)	(3,583,552)	(4,061,261)	(4,238,578)	(4,237,353)	(3,783,207)	(3,343,125)	(2,877,407)	(3,234,962)	(3,103,171)	(2,765,755)	(2,903,553)	(41,419,292)
69	Total Revenue Change	$2,093,194	($1,033,672)	($1,202,017)	($913,206)	($1,000,992)	($1,007,739)	($332,555)	$342,747	$26,159	$287,232	$386,396	$2,585,467	$231,015
70	Percent Change in Base Rate Revenue	56.23%	23.08%	22.68%	26.50%	25.73%	23.86%	29.26%	36.65%	34.05%	36.63%	36.12%	63.98%	33.27%
71	Percent Change in Total Revenue	16.28%	-7.06%	-7.21%	-5.44%	-5.95%	-6.54%	-2.44%	2.94%	0.20%	2.32%	3.36%	22.52%	0.14%

Arizona Electric Power Cooperative, Inc.

ANALYSIS OF REVENUE BY DETAILED CLASS WITH SYNCHRONIZED FPPCA - Staff Adjusted

Line No.	Member	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	TOTAL
1	AVERAGE COST PER KWH - PRESENT REVENUES													
2	ANZA	$0.06014	$0.06545	$0.07216	$0.06682	$0.06652	$0.07088	$0.06380	$0.05914	$0.06556	$0.06660	$0.06395	$0.06056	$0.06538
3	DUNCAN	$0.06607	$0.07457	$0.06957	$0.06728	$0.07077	$0.07212	$0.06859	$0.05907	$0.06532	$0.06346	$0.06824	$0.06364	$0.06773
4	GRAHAM	$0.06637	$0.07577	$0.06957	$0.07033	$0.06860	$0.07224	$0.07102	$0.06396	$0.06299	$0.06412	$0.06779	$0.06323	$0.06831
5	MOHAVE	$0.05928	$0.06086	$0.06155	$0.05937	$0.05943	$0.06160	$0.06210	$0.06338	$0.06291	$0.06402	$0.06809	$0.06580	$0.06192
6	SULPHER	$0.06123	$0.06011	$0.06107	$0.06022	$0.05993	$0.06080	$0.06153	$0.06275	$0.06206	$0.06232	$0.06429	$0.06151	$0.06142
7	TRICO	$0.06691	$0.07505	$0.07288	$0.06830	$0.06934	$0.07132	$0.07164	$0.06922	$0.06434	$0.06383	$0.06637	$0.06226	$0.06878
8	AEPCO CLASS A	$0.06198	$0.06478	$0.06535	$0.06301	$0.06314	$0.06477	$0.06477	$0.06445	$0.06306	$0.06342	$0.06616	$0.06303	$0.06397
9														
10	AVERAGE COST PER KWH - PROPOSED REVENUES													
11	ANZA	$0.06929	$0.06555	$0.06466	$0.05814	$0.05844	$0.06242	$0.06650	$0.06789	$0.06015	$0.06422	$0.06551	$0.07193	$0.06415
12	DUNCAN	$0.07273	$0.06413	$0.05937	$0.05945	$0.05914	$0.06681	$0.07351	$0.07358	$0.06649	$0.06725	$0.07370	$0.07887	$0.06680
13	GRAHAM	$0.07525	$0.06841	$0.05914	$0.05782	$0.05791	$0.06430	$0.07216	$0.07523	$0.06916	$0.07206	$0.08050	$0.07745	$0.06744
14	MOHAVE	$0.07110	$0.05854	$0.05982	$0.05888	$0.05863	$0.05942	$0.06217	$0.06693	$0.06488	$0.06723	$0.07128	$0.08005	$0.06391
15	SULPHER	$0.07036	$0.05813	$0.05969	$0.05895	$0.05866	$0.05914	$0.06113	$0.06335	$0.06067	$0.06155	$0.06381	$0.07387	$0.06230
16	TRICO	$0.07597	$0.06344	$0.06287	$0.06168	$0.06154	$0.06247	$0.06487	$0.06728	$0.06327	$0.06511	$0.06910	$0.07945	$0.06564
17	AEPCO CLASS A	$0.07207	$0.06020	$0.06064	$0.05958	$0.05938	$0.06054	$0.06319	$0.06635	$0.06319	$0.06489	$0.06839	$0.07723	$0.06406

Arizona Electric Power Cooperative, Inc.

CHANGES IN REPRESENTATIVE RATE SCHEDULES - Staff Adjusted

Line No.	RATE DESCRIPTION	MOHAVE ELECTRIC COOPERATIVE	SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE	ALL REQUIREMENTS MEMBERS	TRICO ELECTRIC COOPERATIVE	COLLECTIVE ALL REQIREMENTS MEMBERS
1	PRESENT MONTHLY CHARGES					
2	FIXED CHARGE	$855,113	$757,429	$14.980	$14.980	$14.980
3	O&M CHARGE	$7.260	$7.260	N/A	N/A	N/A
4	TOTAL FIXED CHARGE PLUS O&M CHARGE	$1,894,341	$1,743,462	$14.980	$14.980	$14.980
5	BASE ENERGY CHARGE	N/A	N/A	N/A	N/A	N/A
6	OTHER EXISTING RESOURCE ENERGY CHARGE	N/A	N/A	N/A	N/A	N/A
7	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	N/A	N/A	N/A
8	AVERAGE ENERGY CHARGE	$0.020730	$0.020730	$0.020730	$0.020730	$0.020730
9						
10	PROPOSED MONTHLY CHARGES					
11	FIXED CHARGE	$764,975	$677,366	$931,105	$679,937	$251,168
12	O&M CHARGE	$1,274,882	$1,128,876	$1,178,484	$764,465	$414,019
13	TOTAL FIXED CHARGE PLUS O&M CHARGE	$2,039,858	$1,806,243	$2,109,589	$1,444,402	$665,187
14	BASE ENERGY CHARGE	$0.032147	$0.032285	$0.032345	$0.032383	$0.031558
15	OTHER EXISTING RESOURCE ENERGY CHARGE	$0.068787	$0.066755	$0.067461	$0.066042	$0.061697
16	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	$0.067461	$0.066042	$0.061697
17	AVERAGE ENERGY CHARGE	$0.035943	$0.036711	$0.037211	$0.038824	$0.032791
18						
19	CHANGE IN MONTHLY CHARGES					
20	FIXED CHARGE	($90,138)	($80,063)	N/A	N/A	N/A
21	O&M CHARGE	$235,655	$142,844	N/A	N/A	N/A
22	TOTAL FIXED CHARGE PLUS O&M CHARGE	$145,517	$62,781	N/A	N/A	N/A
23	BASE ENERGY CHARGE	N/A	N/A	N/A	N/A	N/A
24	OTHER EXISTING RESOURCE ENERGY CHARGE	N/A	N/A	N/A	N/A	N/A
25	ADDITIONAL ARM RESOURCES CHARGE	N/A	N/A	N/A	N/A	N/A
26	AVERAGE ENERGY CHARGE	$0.015213	$0.015981	$0.016481	$0.018094	$0.012061

Arizona Electric Power Cooperative, Inc.

TYPICAL BILL ANALYSIS

THIS SCHEDULE IS NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

BILL COUNT

THIS SCHEDULE IS NOT APPLICABLE

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

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-01773A-09-0472

Direct Testimony of

Vincent Nitido

on Behalf of

Trico Electric Cooperative, Inc.

June 1, 2010

EXHIBIT
Trico - 1
ADMITTED

Q. Please state your name and business address.

A. My name is Vincent Nitido and my business address is 8600 West Tangerine Road, Marana, Arizona, 85658

Q. What is your position with Trico Electric Cooperative, Inc. ("Trico" or the "Company")?

A. I am Chief Executive Officer and General Manager of Trico.

Q. What is the purpose of your direct testimony?

A. My direct testimony supports Arizona Electric Power Cooperative, Inc's ("AEPCO") application for new rates. I also urge the Commission to approve Trico's Partial Requirements Capacity and Energy Agreement with AEPCO, as it is an integral component of AEPCO's comprehensive rate settlement agreement with its member distribution cooperatives.

Q. Please describe Trico.

A. Trico is a not-for-profit electric cooperative serving more than 38,000 customers in northwest Tucson, Marana, Mt. Lemmon, Corona de Tucson, Sahuarita, Green Valley, Three Points, Arivaca and adjacent rural areas. Trico has approximately 38,000 customers with approximately 40,000 active meters. We primarily serve residential customers but we have a small but growing number of commercial customers and some large commercial and industrial customers.

As a member-owned cooperative, each of our customers is also a member of the cooperative. We are governed by a seven member board of directors. Trico members

elect fellow members to represent them on the cooperative's board of directors. One representative is elected from each of seven director districts.

Q. Does Trico support AEPCO's proposed rates in this docket?

A. Yes. As indicated in AEPCO's Amended Application in this docket (filed on April 20, 2010), subsequent to AEPCO's initial Application (filed October 1, 2009), AEPCO and its distribution cooperative members continued to meet in an attempt to resolve various issues between the companies, including cost allocation and rate design. After extended negotiations, the parties reached agreement on disputed issues. As a result of those agreements, AEPCO's revenue requirement and rate design were modified. Those modifications are reflected in AEPCO's April 20, 2010 filing.

As a key element in the resolution of the general rate case issues, Trico provided notice to AEPCO on November 20, 2009, that it was exercising its right to convert its Class A membership relationship with AEPCO from an all-requirements relationship to a partial-requirements relationship. Trico's change of status to a Partial Requirements Member ("PRM") was considered and addressed during the course of the rate case negotiations. AEPCO and its members also have agreed upon a modified rate design for AEPCO that would go into effect upon final approval of Trico's PRM status by this Commission and the Rural Utilities Service (RUS). AEPCO and its distribution members are filing a joint request with this Commission for approval of Trico's Partial Requirements Capacity and Energy Agreement and related modifications to the other member agreements (as necessary). Those parties understand that request will be considered in conjunction with this rate case.

Q. Why does Trico support the rates now proposed by AEPCO?

A. Since the conversion of Mohave Electric Cooperative, Inc. (MEC) to partial requirements status with AEPCO in 2001, AEPCO has had different rate structures for its all-requirements members and PRMs. Those differences have resulted in significant cost and rate allocation disputes among the members and AEPCO since that time. The issues and disputes were compounded when Sulphur Springs Valley Electric Cooperative, Inc. (SSVEC) converted to partial requirements status in 2008.

With Trico's conversion to PRM status, more than 90 percent of AEPCO's peak load will consist of PRMs with similar contracts and consistent allocations. That consistency and equity has been the goal of the negotiations among AEPCO and its member cooperatives leading up to the rate settlement among those parties. Trico believes it is fair and in the best interest of all of the parties to have a uniform method of cost and rate allocation.

Q. What is the relationship between the rate case settlement and Trico's conversion to PRM status?

A. As I have indicated, Trico's conversion to PRM status is an integral part of AEPCO's rate settlement with its member distribution cooperatives. The most significant issues among the parties to the settlement discussions hinge on the fair and consistent allocation of AEPCO's costs among its members. Trico does not believe that is possible in an organization with significant differences in cost allocation and rate determination between all-requirements and PRMs. Consequently, Trico exercised its right to convert to PRM status in November 2009, and the parties have negotiated the rate settlement issues since that time with the understanding and intention that Trico's PRM status will coincide with the implementation of AEPCO's new rates. An all-requirements rate was not negotiated or proposed for Trico, and the settlement among the parties works only

with Trico as a PRM. Thus, it is important that the Commission approve the AEPCO rates, Trico's Partial Requirements Capacity and Energy Agreement, the Amendments to the other PRMs' Partial Requirements Capacity and Energy Agreements and the amendments to the all-requirements members' Wholesale Power Contracts, in order for the comprehensive settlement among AEPCO and its members to be realized, and most importantly, for the rates and cost allocation among AEPCO's members to be just and reasonable.

Q. What benefits will Trico realize from becoming a partial requirements member of AEPCO?

A. In addition to the benefits stated previously, Trico believes that PRM status will provide it with increased flexibility and access to economies of scale, in order to meet its customers' electricity needs in the most economical and responsive way, particularly given the anticipated future growth in our service area. PRM status also allows Trico to better meet its renewable energy and energy efficiency obligations under the Commission's rules.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

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-01773A-09-0472

Rebuttal Testimony of

Vincent Nitido

on Behalf of

Trico Electric Cooperative, Inc.

August 30, 2010

EXHIBIT
Trico-2
ADMITTED

Q. Please state your name and business address.

A. My name is Vincent Nitido and my business address is 8600 West Tangerine Road, Marana, Arizona, 85658

Q. What is your position with Trico Electric Cooperative, Inc. ("Trico" or the "Company")?

A. I am Chief Executive Officer and General Manager of Trico.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony supports Arizona Electric Power Cooperative, Inc's ("AEPCO") application for new rates. On behalf of Trico, I am responding to the direct testimony of Arizona Corporation Commission Staff ("Staff"), the rebuttal testimony of AEPCO and the rebuttal of Mohave Electric Cooperative ("MEC"). Specifically, I am providing testimony on behalf of Trico supporting the proposal contained in AEPCO's rebuttal testimony for a debt service coverage ratio (DSC) of 1.32. I also agree with and support the rebuttal testimony of Carl Stover, who provides additional support for AEPCO's position on the DSC.

Q. Does Trico continue to support AEPCO's proposed rates in this docket?

A. Yes. As indicated in my direct testimony in this docket, Trico supports AEPCO's Amended Application in this docket (filed on April 20, 2010), which was the result of extended negotiations between AEPCO and its member cooperatives. Trico further supports the slight modification to those rates set forth in AEPCO's rebuttal testimony.

Q. AEPCO is proposing a revised DSC in its Rebuttal Testimony. Does Trico support the revised DSC?

Trico does support the DSC of 1.32 that AEPCO proposes in its rebuttal testimony. Let me provide some background on the evolution of the DSC. AEPCO's original filed testimony proposed a DSC of 1.35. After extensive analysis and negotiation, AEPCO and its members agreed that a DSC of 1.275 was sufficient for a member-owned Generation and Transmission Cooperative like AEPCO, and would provide adequate operating revenue while minimizing the rate impact on AEPCO's member distribution cooperatives and their customers. AEPCO provided amended testimony supporting that agreement along with its Amended Application.

The direct testimony of the Staff witnesses in this docket recommends a significantly higher DSC of 1.40, while excluding certain non-test year expenses relating to a reduction in employees and an employee incentive plan that is unlikely to achieve a payout.

As Mr. Pierson has indicated in his rebuttal testimony, AEPCO and its members analyzed Staff's recommendation and concluded that taking the non-test year expense reduction into account, a DSC of 1.32 will still provide AEPCO with sufficient operating margins and allow the customers of AEPCO's member distribution cooperatives to share in the reductions in the form of lower rates. As Mr. Pierson indicates AEPCO agreed to submit rebuttal testimony in support of a DSC of 1.32, based on the recommendation and support of all of the AEPCO Members.

Trico supports the modification of the DSC from 1.275 to 1.32. It was arrived through analysis and negotiation consistent with the resolution of the issues agreed to in AEPCO's Amended Application and it is an important element to the overall resolution of the challenging rate issues in this docket.

Q. Has Trico reviewed the surrebuttal testimony of Mohave Electric Cooperative, Inc. ("MEC") witness Carl N. Stover, Jr.?

A. Yes.

Q. Does Trico support Mr. Stover's analysis regarding the competing proposals of AEPCO and Staff?

A. Yes. Trico agrees with Mr. Stover's analysis concerning Staff's revenue recommendations based on a 1.40 DSC, which will lead to an additional $1,403,322 annual revenue increase over what AEPCO is requesting in its rebuttal filing. Mr. Stover's testimony reflects Trico's concerns over Staff's position.

Q. What concerns does Trico have regarding Staff's recommended increase?

A. Mr. Vickroy's recommended increase will put unnecessary additional burden on Trico and its member-customers because, under Staff's proposal, Trico believes that AEPCO will be charging more than necessary to maintain sufficient net margin and cash flow after servicing debt. That is borne out by the agreed upon revenue requirement submitted by AEPCO in its rebuttal testimony and by Mr. Stover's rebuttal testimony.

Q. Can you describe those concerns in more detail?

A. Certainly. Trico believes it and its member-customers should not be burdened with any more of an increase than necessary to provide AEPCO with sufficient net margin and cash flow to run its operations. Trico, being a distribution cooperative, has been in the position of requesting increases to rates twice in the past six years. At the same time, Trico has sought to increase rates only when necessary and only to the extent necessary to cover operating expenses and provide a sufficient margin so that it can continue to operate. Considering the current economic climate, any increase should be no more than necessary. Trico is unconvinced that Mr. Vickroy's recommendation for AEPCO is

essential for AEPCO. To the contrary, AEPCO's rebuttal filing indicates that it believes less of an increase is required.

Q. Does this conclude your testimony?

A. Yes, it does.