OPEN MEETING ITEM

ORIGINAL

ARIZONA CORPORATION COMMISSION

DATE: June 27, 2005

DOCKET NO: E-01773A-04-0528 and E-04100A-04-0527

TO ALL PARTIES:

Enclosed please find the recommendation of Administrative Law Judge Jane Rodda. The recommendation has been filed in the form of an Opinion and Order on:

ARIZONA ELECTRIC POWER COOPERATIVE, INC. and
SOUTHWEST TRANSMISSION COOPERATIVE, INC.

(RATES)

Pursuant to A.A.C. R14-3-110(B), you may file exceptions to the recommendation of the Administrative Law Judge by filing an original and thirteen (13) copies of the exceptions with the Commission's Docket Control at the address listed below by **4:00 p.m.** on or before:

JULY 6, 2005

The enclosed is NOT an order of the Commission, but a recommendation of the Administrative Law Judge to the Commissioners. Consideration of this matter has tentatively been scheduled for the Commission's Open Meeting to be held on:

JULY 12 and 13, 2005

For more information, you may contact Docket Control at (602)542-3477 or the Hearing Division at (602)542-4250. For more information about the Open Meeting, contact the Executive Secretary's Office at (602) 542-3931.

BRIAN C. McNEIL
EXECUTIVE SECRETARY

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC, FOR A RATE INCREASE.	DOCKET NO. E-01773A-04-0528
IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC., FOR A RATE INCREASE.	DOCKET NO. E-04100A-04-0527 DECISION NO. ____________ **OPINION AND ORDER**

DATE OF HEARING:	April 14, 2005
PLACE OF HEARING:	Tucson, Arizona
ADMINISTRATIVE LAW JUDGE:	Jane L. Rodda
APPEARANCES:	Michael M. Grant, Gallagher & Kennedy, PA, on behalf of Arizona Electric Power Cooperative, Inc.; Michael A. Curtis, Curtis, Goodwin, Sullivan, Udall & Schwab, PLC, on behalf of Mohave Electric Cooperative, Inc.; Christopher Hitchcock, Law Offices of Christopher Hitchcock, for Sulphur Springs Valley Electric Cooperative; John Leonetti, in propera persona; and Timothy Sabo and Diane Targovnik, Commission Legal Division for the Utilities Division.

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Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. On July 23, 2004, Arizona Electric Power Cooperative, Inc. ("AEPCO" or

"Cooperative") filed an Application for General Rate Increase.[1]

2. AEPCO is a nonprofit member owned cooperative that provides power generation service to six Class A member distribution cooperatives. The distribution cooperatives provide electricity at retail to their member owners. Prior to 2001, AEPCO provided both generation and transmission service to its members. In Decision No. 63868 (July 25, 2001) the Commission approved the reorganization of AEPCO into three separate and affiliated cooperatives: AEPCO provides generation; Southwest Transmission Cooperative Inc. ("SWTC") provides transmission; and Sierra Southwest Cooperative ("Sierra") provides wholesale marketing and support services to AEPCO and SWTC.

3. AEPCO's Class A members are Anza Electric Cooperative, Inc. ("Anza"), located entirely in California; Duncan Valley Electric Cooperative, Inc. ("DVEC"), located partially in New Mexico; Graham County Electric Cooperative, Inc. ("GCEC"); Sulphur Springs Valley Electric Cooperative, Inc. ("Sulphur Springs"); Trico Electric Cooperative, Inc. ("Trico"); and Mohave Electric Cooperative, Inc. ("Mohave"). Currently, Mohave is a partial requirements member, and Sulphur Springs is in the process of converting to a partial requirements member.[2] Partial requirements members contract with AEPCO to furnish only a portion of its retail electricity requirements and must plan for and secure the balance of its generation needs from either AEPCO or another generator. All other Class A members are full requirements members which means they obtain all of their generation service from AEPCO.

4. On August 27, 2004, Commission Utilities Division Staff ("Staff") notified AEPCO that its Application met the sufficiency requirements of A.A.C. R14-2-103. Staff classified AEPCO a Class A utility.

5. Counsel for AEPCO and Staff requested a Procedural Conference prior to the Hearing Division issuing its Procedural Order setting the matter for hearing. Pursuant to Procedural Order dated September 3, 2004, a Procedural Conference was held on September 9, 2004. AEPCO

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[1] On the same date, its affiliate, Southwest Transmission Cooperative, Inc. ("SWTC") filed a rate application (Docket No. E-04100A-04-0527).

[2] For purposes of the application, Sulphur Springs is treated as a full requirements customers because it was during the test year and it is unknown when the necessary approvals will be obtained to convert to a partial requirements member.

requested an expedited schedule for filing testimony and conducting the hearing based on the Commission's prior indication that it would be flexible when considering rate applications from cooperatives, and upon the allegation that AEPCO was losing money and would be in technical default of financial ratios set by its lenders. Staff opposed the expedited schedule because the issues in this case are potentially complex and Staff wanted to be sure that all issues received adequate analysis. Staff claimed it needed the full 180 days allowed under Commission Rules for Staff to file testimony in a Class A utility rate case. In addition, Staff requested that the AEPCO and SWTC rate applications be consolidated on the grounds that they are affiliates and there will be issues and witnesses in common which favor consolidation. Staff feared that if the records were not consolidated, one or the other might be incomplete. AEPCO and SWTC opposed consolidation, believing that it might lead to confusion.

6. By Procedural Order dated September 15, 2004, the Commission denied the request for an expedited schedule. The applications are the first rate cases for AEPCO and SWTC since the restructuring, and the Commission found that the need for a thorough analysis outweighed the request for expedited treatment. In addition, because the applications involve affiliates and their rate cases will involve several inter-related issues, the Commission consolidated the matters for hearing.

7. The September 15, 2004, Procedural Order established deadlines for filing testimony and set the hearing to commence April 14, 2005, at the Commission's offices in Tucson, Arizona.

8. On January 11, 2005, AEPCO filed a Notice of Filing that indicated it had mailed notice of the hearing to its members and customers and had caused the notice of the hearing to be published in newspapers and in the newsletters of its member distribution cooperatives, as required by the September 15, 2004, Procedural Order.

9. Intervention was granted to Mohave on November 2, 2004; to Sulphur Springs on January 25, 2005; and to John T. Leonetti, a resident in Trico's service territory, on March 10, 2005.

10. With its Application, AEPCO filed the direct testimony of Dirk Minson, AEPCO's Chief Financial Officer; Gary Pierson, Manager of Financial Services for Sierra and who provides treasury, cash management, risk management and rate design/implementation functions for AEPCO; Stephen Daniel, the Executive Vice President of GDS Associations, a consultant for AEPCO who

testified about cost allocation methodology; and William Edwards, an economist and Vice President of Regulatory Affairs for the National Rural Utilities Cooperative Finance Corporation ("CFC"). Pursuant to the September 15, 2004 Procedural Order, Staff filed the direct testimony of Crystal Brown, Alejandro Ramirez, Barbara Keene and Jerry Smith on February 23, 2005. On March 16, 2005, AEPCO filed the rebuttal testimony of Messrs. Minson and Pierson. On April 4, 2005, Staff filed the surrebuttal testimony of Ms. Brown, Ms. Keene and Mr. Ramirez.

11. The hearing convened as scheduled on April 14, 2005, before a duly authorized Administrative Law Judge.

12. AEPCO, Staff, Mohave and Mr. Leonetti filed Closing Briefs.

13. In the course of this proceeding the Commission received at least 23 letters and phone calls from customers of the distribution cooperatives in opposition to the proposed increase.

14. In the test year ended December 31, 2003 ("Test Year"), according to Staff, AEPCO had Adjusted Operating Revenue of $138,919,725, resulting in Adjusted Operating Income of $10,425,443. AEPCO had a margin loss of $711,329, and its Debt Service Coverage Ratio ("DSC") had slipped to 0.70, below the Rural Utilities Service ("RUS") mortgage minimum requirement of 1.0. AEPCO suffered another operating loss in 2004, and is no longer in compliance under the terms of its mortgage or pursuant to the rules of the RUS, primarily 7 CFR 1710.114. At the end of the Test Year, AEPCO's equity comprised 4.8 percent of its capitalization, but continued losses have caused its equity to drop to approximately 3 percent.

15. AEPCO blamed the poor operating results in the Test Year and subsequently on higher delivered coal and natural gas costs, increased maintenance costs associated with an aging generation plant at the Apache Generating Station, and necessary capital additions to meet load growth on the Class A members' distribution systems.

16. AEPCO's current rates for Class A members were authorized in Decision No. 58405 (September 3, 1993) and Decision No. 62758 (July 22, 2000). Decision No. 58405 authorized a Times Interest Earned Ratio ("TIER") of 1.05 and a DSC of 1.0 to provide a 12.96 percent rate of return on rate base. Decision No. 62758 authorized the Cooperative's competitive transition charge.

17. In its application, AEPCO sought approval for annual revenues of $146,061,466, an

increase of $7,141,741, or 5.14 percent over adjusted Test Year revenues. According to the Cooperative, its request would have produced an operating margin of $16,422,692, a net margin of $3,922,406, TIER of 1.29 and DSC of 1.05. The Cooperative calculates TIER and DSC using the same formula as the RUS, which includes non-operating revenue. In its application, the Cooperative had claimed an adjusted rate base of $222,147,011, and its requested increase would have resulted in a rate of return of 7.39 percent.

18. In surrebuttal, Staff recommended a revenue requirement of $148,397,723, an increase of $9,477,998, or 6.82 percent over Test Year adjusted revenues. Staff's recommended revenue level would yield an operating margin before interest of $19,903,441, a 10.5 percent rate of return on an original cost rate base of $189,637,810, and provide a 1.50 TIER and a DSC of 0.99. The formula that Staff utilizes to calculate DSC does not include non-operating income and results in a more conservative calculation.

19. After reviewing Staff's direct and surrebuttal testimony, AEPCO revised its revenue request in its rejoinder testimony, and even further by the date of the hearing. As its final position, AEPCO sought a total revenue requirement of $152,279,043. In addition AEPCO agreed to all of Staff's recommendations on rate base. Staff and AEPCO agreed that because of its cooperative structure, cash flow and debt coverage ratios were more relevant to determining AEPCO's required revenue requirement than the rate of return on rate base. Thus, at the hearing, Staff and AEPCO agreed that to generate sufficient cash flow for debt service, to meet its capital investment needs and to increase its equity, AEPCO should be authorized a revenue increase of $13,359,318, or 9.6 percent for a total revenue requirement of $152,279,043.

20. AEPCO proposed that in order to come back into compliance with its mortgage requirements and to minimize the impact of the revenue increase, $10,751,925 of the increase should become effective immediately, and that the remaining $2,607,393 of the increase should be phased in over the following two years. The first phase of the rate increase would yield a TIER of 1.59 and a DSC of 1.04 (utilizing Staff's calculation methodology), and would result in a rate of return of 11.17 percent on adjusted original cost rate base ("OCRB").

21. In the second phase, which would become effective after one year, or August 1, 2006,

revenues would increase an additional $1,295,119. Phase Two would result in total revenues of $150,966,969, and yield a TIER of 1.69, a DSC of 1.08, and a rate of return on OCRB of 11.86 percent.

22. Phase Three would result in an additional increase of $1,312,274, and would go into effect on August 1, 2007. This phase would yield total revenue of $152,279,043, resulting in a TIER of 1.79, DSC of 1.13 and rate of return of 12.54 percent on OCRB.

23. AEPCO estimates that on the retail level, the Phase One increase would result in an approximate $3.70 monthly bill increase for an average residential customer of its member distribution cooperatives who uses 750 kWh. AEPCO estimates the combined effect of the deferred increases in 2006 and 2007 would produce another approximate $0.90 monthly retail increase spread over the next two years.

24. AEPCO designed Phases Two and Three to generate additional revenue to allow the Cooperative to maintain its equity balances as additional principal payments become due in 2006 and 2007. (TR at 151-53).

25. AEPCO's Board of Directors did not have an opportunity to approve the proposed step increases prior to the hearing. AEPCO submitted a resolution of the Board approving the step increase proposal as a late-filed exhibit. The resolution contains the following proviso:

> However, the AEPCO Board of Directors requests that the effective rate order provide that the 1.5 percent increases will only be enacted after a submittal by AEPCO of relevant financial information to the ACC prior to the scheduled increases, and only if this information demonstrates that the rate increases are necessary to achieve a Debt Service Coverage Ratio of 1.0 . . . . AEPCO staff is instructed to submit all such financial information to the Board for approval prior to its submission to the ACC.

26. Commission Staff does not support the proviso adopted by the AEPCO Board because the term "relevant financial information" is undefined and it seems to suggest that future orders of the Commission would be necessary to "enact" the step increases. In addition, Staff notes that the AEPCO Board might be able to block any step increases simply by failing to forward the information. More fundamentally, Staff argues, the conditional approach adopted by AEPCO's Board appears to be based on the notion that a DSC of 1.0 is reasonable and prudent, and perhaps

excessive, while it is Staff's view that a DSC of 1.0 is the absolute minimum, and leaves no room for unexpected events. Staff argues the proviso makes it nearly impossible to build equity. Staff recommends that the Commission approve the step increases without condition or need for future order of the Commission.

27. Intervenor Leonetti opposed any rate increase for AEPCO at this time. Mr. Leonetti believed that although the target DSC of 0.99 and TIER of 1.5 are reasonable in light of testimony indicating that the RUS and CFC require a minimum DSC of 1.0 and minimum TIER of 1.05, he argued that neither AEPCO nor Staff demonstrated that the rates they agreed to are reasonable. In addition to the lenders' target financial ratios, Mr. Leonetti argues that the Commission should consider the effect of the proposed rate increase on ratepayers (Leonetti Brief at 2).

28. Mohave, one of AEPCO's Class A Members, and represented on AEPCO's Board of Directors, supports the step increase, as proposed by AEPCO, and as conditioned by the AEPCO Board of Directors. Mohave adds that in developing their revenue recommendations, Staff did not consider basic differences between the all-requirements and partial-requirements customers of AEPCO.

29. We agree with Staff that AEPCO's proposed conditions for the step increases appear unnecessarily complicated and could delay the implementation of the rates we find necessary to restore AEPCO's financial health. The conditions were proposed for the first time after the hearing and neither Staff, the non-member intervenor, nor the Commission could cross examine the proponents concerning how the conditioned increases would be enacted. A total revenue level of $152,279,043, as was proposed at the hearing, is fair and reasonable and fully supported by the evidence. The revenue increase is designed not only to meet lenders' minimum financial ratio requirements, but to permit the Cooperative to build much needed equity. If events demonstrate that AEPCO is able to build equity consistent with the goals established later in this Order, AEPCO may consider filing an application to modify rates. AEPCO has stated it would be filing another rate application in three to five years in any event. The future conversion of Sulphur Springs to a partial requirements member may also affect the timing of the next rate case. There is no evidence that the rates agreed to by Staff and AEPCO are unfair to any member or end user. We adopt the phased in

approach in an effort to minimize the immediate impact on rate payers.

30. AEPCO and Staff agreed on the rates to be implemented to achieve the revenue requirement. The schedule of proposed rates is attached hereto as Exhibit A. We find that a revenue requirement of $152,279,043, is fair and reasonable, and that it is in the public interest that the revenue increase be phased in over two years as set forth in Exhibit A.

31. Mohave recommends that AEPCO file a rate case six months after Sulphur Springs has completed a full year as a partial requirements member.

32. Mohave's recommendation that AEPCO file a rate application after a full year of operating data after Sulphur Springs has become a partial requirements member is well-founded. Sulphur Springs is one of AEPCO's largest members and its change of status may have significant impact on AEPCO's revenues. Thus, we will adopt Mohave's recommendation.

33. Staff and AEPCO agree that an adjusted original cost rate base of $189,637,810 is fair and reasonable. No party objected to Staff's rate base adjustments. Based on the evidence, we concur that Staff's adjustments to rate base are reasonable and should be adopted. AEPCO waived a reconstruction cost new rate base and thus, its original cost rate base is the equivalent of its fair value rate base.

34. Staff and AEPCO also agree that a Fuel and Purchased Power Cost Adjustor ("FPPCA") should be established for AEPCO. Staff explained that the FPPA would track changes in the cost of fuel for AEPCO's generating units and power purchased from others and would be calculated by comparing the rolling 12-month average of actual fuel and purchased power costs to the base cost established in this rate case. The rate would be applied to the member bills as a kilowatt-hour charge. Whether AEPCO's distribution cooperative members could pass additional FPPCA charges on to end-users would depend on whether they had purchased power adjuster clauses in their tariffs. Under Staff's proposal, the adjustor rate, initially set at zero, would be reset semi-annually on October 1, 2006, and April 1, 2007, and thereafter on October 1 and April 1 of each subsequent year. AEP would submit a publicly available report, with a revised tariff, that shows the calculation of the new rate on September 1, 2006 and March 1, 2007, and thereafter on September 1 and March 1 of each subsequent year. The adjustor rate would become effective with billings for October and April

unless suspended by the Commission. AEPCO accepted all of Staff's recommendations on clause administration and reporting as set forth in Ms. Keene's direct testimony.

35. With respect to the FPPCA, Staff further recommends:

a. The FFPCA will expire in five years unless extended by the Commission;

b. The Commission or Staff will have the right to review the prudence of fuel and power purchases at any time;

c. The Commission or Staff will have the right to review any calculations associated with the FPPCA at any time;

d. Any costs flowed through the FPPCA are subject to refund if the Commission determines that the costs are imprudent;

e. AEPCO will file monthly reports with Staff's Compliance Section detailing all calculations relating to the FPPCA and containing the nine minimum requirements specified in Ms. Keene's Direct Testimony (Ex. S-7);

f. AEPCO will file additional monthly reports regarding its generating units, power purchases, and fuel purchases. The report will comply with the minimum requirements specified in Ms. Keene's Direct Testimony.

36. AEPCO's fuel and purchased power expenses amounted to almost one-half of AEPCO's total expenses for the adjusted 2003 test year. AEPCO asserted that the volatility was a primary reason AEPCO suffered a margin loss in the Test Year. The FPPCA will allow timely recovery of increases in fuel and purchased power costs, or allow the refund of any decreases, without the time and expense of a full rate proceeding. No party objected to Staff's recommendations for the FPPCA. We agree that the FPPCA should be approved on the terms agreed to by the parties.

37. Staff agrees with AEPCO that a separate base cost of power be established for full-requirements and partial-requirements customers. Staff recommends that the base cost of power for full-requirements customers should be set at $0.01687 per kWh and that the base cost of power for

partial-requirements customers should be set at $0.01603 per kWh. AEPCO agreed with Staff's recommended rates.

38. As part of this proceeding AEPCO requested the approval of revised depreciation rates. The lower depreciation rates are based upon a study and would lower costs in the Test Year by slightly more than $1.47 million Staff agreed that the revised depreciation rates, as shown on Exhibit DCM-1 of Dirk Minson's Direct Testimony (Ex. AEPCO-1) should be approved.

39. Staff recommends that the Commission approve a Demand Side Management (DSM) adjustor.

40. AEPCO does not agree that as a wholesale generator, AEPCO should engage in DSM programs. The parties have agreed to reserve the issue of the specific DSM requirements for AEPCO to the pending DSM rulemaking docket (Docket No. RE-00000C-05-0230). (Staff Brief at 6) AEPCO agrees with Staff that the Commission should approve a DSM adjustor mechanism.

41. Mohave recommends that the Commission provide that in any DSM requirement, that each distribution cooperative be responsible for its own program and not be subject to AEPCO's direction.

42. We find that it is reasonable to determine AEPCO's obligations with respect to specific DSM programs in the DSM rulemaking docket, but that in anticipation of the adoption of those rules and the potential that AEPCO may engage in DSM programs, approving a DSM adjustor mechanism at this time is reasonable.

43. AEPCO's equity ratio is far below sample generation and transmission cooperatives which have a national median equity level of 13 percent. (Ex AEPCO 6 – page 10). Staff's witness used a comparison group of cooperatives that are rated by Standard and Poors that had an average equity of 19 percent. (Ex S-11 and S-12)

44. Staff recommends that AEPCO file a capital improvement plan by March 31, 2006. Staff further recommends that the Commission set an equity goal for AEPCO of 30 percent. Staff based its recommended goal on: (1) the goals set in prior orders concerning AEPCO (Decision No. 64227); (2) AEPCO's need to achieve greater financial flexibility; and (3) an article by Fitch Ratings which states that an equity-to-capitalization ratio between 25 to 30 percent is adequate for a

generation and transmission cooperative. (Ex S-12 at 6) Staff notes that in Decision No. 67748 (April 11, 2005), the Commission recently approved the same 30 percent equity goal for Graham County Utilities.[3] Staff believes the 30 percent equity goal would be consistent with RUS regulations which limit patronage refunds until 30 percent equity is achieved.

45. Staff further recommends that the Commission limit AEPCO from making patronage refunds. Specifically, Staff recommends that AEPCO should not be permitted to make any patronage refunds while its equity level remains below 20 percent of total capitalization. If AEPCO's equity level is between 20 percent and 30 percent, Staff recommends that patronage refunds be limited to 25 percent of net earnings, which Staff states parallels the RUS regulations.

46. Staff also recommends that to ensure AEPCO makes progress in building equity, that it should be required to file a rate case no later than 3 to 5 years from the date of this Decision.

47. AEPCO does not oppose filing an equity improvement plan or the requirement it file a rate case not later than five years. AEPCO opposes, however, the concept that 30 percent equity is an appropriate goal for the Commission to adopt. AEPCO cites evidence that the average and median equity levels for generation and transmission cooperatives nationwide is much lower. AEPCO also argues that there are many factors, besides equity, which impact the financial strength of AEPCO. According to AEPCO, Fitch Ratings looked at some 12 different factors in assigning a rating to Golden Spread Electric Cooperative (the subject of the article relied upon by Staff) including the strength of its requirements contracts, management quality, adequate liquidity, overall financial profile, DSC and TIER, as well as equity. AEPCO argues that neither it, nor the Commission, would want to be in the difficult position where unnecessarily high rate increases are driven by an equity target that is inflexible and arbitrarily set.

48. Mohave recommends that the Commission require AEPCO to file an Equity Improvement Analysis by March 31, 2006, which should include: 1) an analysis of the benefits, if any, that Partial Requirement Members ("PRMs") obtain by improving the equity position of AEPCO; 2) an analysis of the benefits All Requirements Members ("ARMs") obtain by improving

[3] Graham County Utilities, Inc., ("GCU") is a cooperative owned by Graham County Electric Cooperative, Inc. to provide natural gas and water service. Graham County Electric Cooperative is the Class A member of AEPCO.

the equity position and of the optimum equity level to obtain such benefits; 3) an analysis of methods other than rate increases for increasing equity; and 4) a consideration of possible methods to permit future borrowing to meet load growth of ARMs to be based upon the equity of those ARMs that benefit from the borrowing.

49. AEPCO provides wholesale service to six distribution cooperatives. Mohave states that typically, a generation cooperative will plan to serve the total power supply requirements for all of its members, however, AEPCO does not have the same power supply obligation for each of the six members. Two of the six members—Mohave and Sulphur Springs—have elected to change from all requirements members to partial requirements members. Mohave states that these two members reflect approximately 65 percent of the Test Year power supply requirements billing units. According to Mohave, AEPCO does not have to plan for serving, nor does it have the responsibility to serve, the load growth of the partial requirements members in excess of the allocated AEPCO resources. Mohave asserts AEPCO has no future capital requirements associated with new resources to serve approximately 65 percent of the total member load. Mohave argues that Staff's recommended revenue requirement is based on the need to maintain financial stability to finance future plant additions and replacements[4], and Mohave believes there is a question of the fairness of a requirement that a customer who will not cause, and is not allowed to participate in, the future event to have revenue responsibility for that event. Mohave argues that prior to allowing the allocation of any revenue responsibility associated with a future event to a partial requirements member, there should be findings as to whether or not the proposed assets will be used and useful in serving the partial requirements member. Mohave asserts the record in this proceeding is devoid of data relating to future capital needs required to serve a partial requirements member.

50. Mohave asserts that the equity level recommended by Staff is excessive, as the lender has indicated that it is not necessary to achieve the Staff recommendations in order to obtain financing. In addition, Mohave asserts that Staff did not analyze the impact on the ratepayer in developing its equity recommendations.

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[4] Mohave asserts that one of Staff's justifications for the proposed increase in equity is to make certain that AEPCO has access to capital markets to provide debt capital to build future power supply resources.

51. In Decision No. 64227 (November 29, 2001) the Commission approved AEPCO's financing request and ordered AEPCO to file a capital plan by December 31, 2002. In that docket, Staff recommended that AEPCO increase its equity to 10 percent by December 31, 2006, to 15 percent by December 31, 2010, and to 30 percent by December 31, 2015.

52. AEPCO filed the Capital Plan required by Decision No. 64227 on December 23, 2002, and provided a copy as a late-filed exhibit in this docket. AEPCO's December 2002 Capital Plan indicates that equity levels were projected to reach 12 percent in 2006, 27 percent in 2010 and 31 percent in 2011. As is evident from it current rate application, AEPCO's assumptions that formed the basis of its December 2002 Capital Plan did not materialize.

53. The evidence presented in this proceeding indicates that AEPCO must improve its equity position. It is currently not in compliance with its lenders' equity requirements. The evidence is inconclusive, however, to make a finding at this time that a 30 percent capital requirement is an appropriate goal for a generation cooperative such as AEPCO. Mr. Edwards testified that the median equity ratio for a generation and transmission cooperative is 13.22 percent in 2002, the most recent available year of data. Furthermore, the RUS and CFC do not discriminate on the price of loans based on equity levels. (TR at 63). There is some evidence that adopting and enforcing an equity goal of 30 percent may place undue upward pressure on rates and that a 30 percent equity level is not required to protect AEPCO's ability to access the financial markets. On the other hand, just because national averages for generation and transmission cooperatives are below 20 percent, does not mean that we should not strive for equity greater than that to give the cooperative a cushion to weather economic setbacks. AEPCO did not present sufficient evidence to allow us to determine that a specific goal less than 30 percent is reasonable. In his rebuttal testimony, Mr. Minson testified that the revenues that the Cooperative was recommending at that time (somewhat less than their final position) would allow AEPCO to reach 30 percent equity in about eight years. (Ex A-2 at 8). If Mr. Minson is correct, then AEPCO should be in compliance with Staff's recommendations set forth in Decision No. 64227. We believe that AEPCO should update its December 2002 Capital Improvement Plan, with updated assumptions and provide an analysis of the rates that would be required to achieve an equity level of 30 percent, within ten years, or 2015. We do not adopt a

requirement now, nor does Decision No. 64227 specifically require, that AEPCO achieve any specific equity goal. We do adopt the rates herein with the expectation that AEPCO will be able to build much needed equity. Because we are requiring AEPCO to file another rate case in no more than five years, in any case, adopting an ultimate goal of 30 percent at this time is not necessary.

54. Whereas Mohave raises interesting issues regarding the differences between partial and full requirements members, it makes its position known for the first time in its Closing Brief. Mohave did not file testimony in this case. Mohave and Sulphur Springs are two of AEPCO's largest members. We believe Mohave's suggestion that the capital improvement plan that AEPCO will file in 2006 should specifically address its obligations to partial requirements members is well-founded, and direct AEPCO to include such analysis in its 2006 updated report.

55. AEPCO did not file jurisdictionally separated information for Anza in this rate case, nor has it ever filed such information in any prior rate case.

56. Staff recommends that in its next rate case, AEPCO prepare jurisdictionally separated schedules for Anza.

57. Commission rule R14-2-103(B)(4) provides in relevant part:

> Separation of nonjurisdictional properties, revenues and expenses associated with the rendition of utility service not subject to the jurisdiction of the Commission must be identified and properly separated in a recognized manner when appropriate. In addition, all nonutility properties, revenues and expenses shall likewise be segregated.

58. Staff argues that jurisdictional separation is an important tool that Staff uses to ensure that rates are fair and cost-based. Staff states that Duncan Valley Electric Cooperative Inc., Garkane Power Association, Inc. and Columbus Electric Cooperative, all cooperatives within the Commission's jurisdiction with multi-state operations, file jurisdictionally separated information. Staff does not believe arguments that a separation study would be too costly in comparison with the expected benefits justify a waiver of the requirement. Staff also asserts that once the first study is prepared, future separations will be substantially easier.

59. AEPCO opposed the recommendation to jurisdictionally separate its operations associated with Anza. According to AEPCO, Anza's load represents only 1.5 percent of AEPCO's total energy sales in 2003. AEPCO estimates the cost of a separation study would be $40,000 to

$60,000 and the cost of service differences for Anza, if any, would not justify the expense or the effort to evaluate its findings. Under these circumstances, AEPCO argues that to prepare such study would be an "undue burden," which is one of the grounds for waiver under A.A.C. R14-2-103.B.6.

60. We find that it is premature for the Commission to determine if a waiver of the requirement to file a jurisdictional separation study for Anza should be in connection with AEPCO's next rate case. We believe that AEPCO should have the opportunity to request such waiver prior to, or in connection with its next rate filing, but we cannot pre-judge whether the circumstances present today concerning Anza's load will be present in the future.

CONCLUSIONS OF LAW

1. AEPCO is a public service corporation pursuant to Article XV of the Arizona Constitution and A.R.S. §§ 40-282 and 40-285.

2. The Commission has jurisdiction over AEPCO and the subject matter of the application.

3. Notice of the proceeding was provided in conformance with law.

4. The stipulated rates and charges as set forth in and approved herein, and attached as Exhibit A, are reasonable.

5. The recommendations set forth in the Findings of Fact discussed hereinabove are reasonable and should be adopted in accordance with the discussion therein.

ORDER

IT IS THEREFORE ORDERED that the rates and charges set forth in Exhibit A are approved and Arizona Electric Power Cooperative, Inc. shall file on or before July 29, 2005, a tariff that complies with the rates and charges approved herein.

IT IS FURTHER ORDERED that the rates and charges for Phase One shall be effective for all service provided on and after August 1, 2005; the Phase Two rates shall be effective August 1, 2006; and Phase Three rates shall be effective August 1, 2007.

IT IS FURTHER ORDERED that within 15 days of the effective date of this Order, AEPCO shall notify its member/customers of the rates and the effective dates approved herein.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall file a rate case six months after Sulphur Springs Valley Electric Cooperative, Inc. has completed a full year as a partial requirements member, or not later than five years after the effective date of this Decision, whichever is earlier.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall amend its tariffs to include a Fuel and Purchased Power Cost Adjustor as described herein.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall amend its tariff to include a DSM adjustor mechanism as discussed herein.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall file by March 31, 2006, an equity improvement plan that will indicate the effect on AEPCO's equity under the rates approved herein and an analysis of the effect on rates if equity of 30 percent of total capitalization is to be reached by 2015, as well as an analysis of the benefits and equities of capitalization on its partial requirements and full requirements members.

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IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall not make any patronage refunds while its equity level remains below 20 percent of total capitalization, and patronage refunds be limited to 25 percent of net earnings if its equity is between 20 and 30 percent of its capitalization.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this _____ day of _________, 2005.

BRIAN C. McNEIL
EXECUTIVE SECRETARY

DISSENT ____________________________

DISSENT ____________________________

JR:mj

SERVICE LIST FOR: ARIZONA ELECTRIC POWER COOPERATIVE, INC.

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

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EXHIBIT A

Effective Date	August 1, 2005	August 1, 2006	August 1, 2007
All Requirements Members:			
Demand rate - $/kW Month	14.31	14.64	14.98
Energy Rate - $/kWh	0.02073	0.02073	0.02073
Power Cost Adjustor Base - $/kWh	0.01667	0.01667	0.01667
Partial Requirements Members:			
Fixed Charge - $/month	790,722	822,728	855,113
O&M Rate - $/kWMonth	7.15	7.21	7.26
Energy Rate - $/kWh	0.0273	0.0273	0.0273
Power Cost Adjustor Base - $/kWh	0.1603	0.1603	0.1603