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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

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-12-0305

AEPCO'S NOTICE OF FILING REBUTTAL TESTIMONY

Pursuant to Procedural Orders dated September 11, 2012, March 5, 2013 and May 29, 2013 in this docket, attached are the Rebuttal Testimonies of Gary E. Pierson and Richard P. Kurtz on behalf of the Arizona Electric Power Cooperative, Inc.

RESPECTFULLY SUBMITTED this 13th day of June, 2013.

Arizona Corporation Commission
DOCKETED
JUN 13 2013
DOCKETED BY

GALLAGHER & KENNEDY, P.A.

By
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10421-67/3541047

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

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-12-0305

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Rebuttal Testimony of Gary E. Pierson

on Behalf of

Arizona Electric Power Cooperative, Inc.

General Rates Application

June 13, 2013

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

A. Yes, I am.

Q. Have you reviewed the direct testimonies of Staff witnesses Messrs. Vickroy, Kalbarczyk, Mazzini and Antonuk which were filed in this matter?

A. Yes, I have. My rebuttal testimony provides AEPCO's responses to certain issues raised by Messrs. Vickroy, Kalbarczyk and Antonuk. I also present revised recommended revenue requirements and rates in support of and consistent with AEPCO's rebuttal positions. Mr. Kurtz' rebuttal testimony will address Mr. Mazzini's testimony.

COST OF CAPITAL AND RATE SUFFICIENCY — AEPCO REBUTTAL POSITION

Q. Mr. Vickroy filed direct testimony on Staff's behalf presenting his evaluation and recommendations regarding cost-of-capital issues for the AEPCO rate filing. Please provide the Company's response to Mr. Vickroy's testimony.

A. AEPCO agrees with Mr. Vickroy's conclusion that a Debt Service Coverage ("DSC") range of 1.20 to 1.50 is appropriate to determine rate sufficiency. AEPCO's requested 1.32 DSC falls comfortably within that range. Therefore, we do not agree with Mr. Vickroy's suggestion that AEPCO leave its revenues at the present levels, which would result in a test year DSC of 1.56. First, obviously, that level of DSC is outside the sufficiency range of 1.20 to 1.50 which we both agree on. Second, AEPCO consulted with its Member Distribution Cooperatives on an appropriate DSC, both prior to filing this application, as well as after Mr. Vickroy filed his testimony recommending that we forego our requested decrease in revenue requirements. There is a consensus among the Members and AEPCO that it is still appropriate to set revenues based upon a DSC of 1.32 – a position inside the sufficiency range.

Finally, the primary factor relied upon by Mr. Vickroy in making his 1.56 DSC recommendation appears to be a concern over the impact of the EPA Regional Haze Federal Improvement Plan ("FIP"). At page 18 of his testimony, he summarizes Staff's concerns about AEPCO's "much greater business risk due to EPA environmental mitigation requirements." While we appreciate that concern, AEPCO does believe it has made substantial progress with EPA toward a reasonable <u>and</u> cost-effective solution.

In that regard, AEPCO filed a supplement to its Petition for Administrative Reconsideration with the EPA on May 29, 2013. It set forth AEPCO's Best Available Retrofit Technology ("BART") proposal for Apache Steam Units 2 and 3. If accepted by the EPA, the AEPCO compliance plan – consisting of the switch to natural gas for Steam Turbine Unit 2 and the installation of a SNCR retrofit for Steam Turbine Unit 3 – would require only approximately $30 million in capital requirements in contrast to the estimated $200 million-plus cost of the current FIP. On June 6, 2013, the EPA granted partial reconsideration of its FIP in response to AEPCO's proposed BART alternative. AEPCO believes its proposal will be given serious consideration by the EPA.

For all of these reasons, AEPCO continues to urge the Commission to approve our 1.32 DSC request and set rates accordingly.

Q. On pages 3-4 of his testimony, Mr. Vickroy discusses the "deterioration" of AEPCO's financial results and coverage ratios in 2011 and 2012. Please provide the Cooperative's response.

A. While Mr. Vickroy is correct that AEPCO fell short of the DSC results authorized in our last rate case, his analysis did not take into account one-time adjustments to financial results recorded in both 2011 and 2012. First, in 2011, the Commission approved our request to write off and not recover $1.998 million of certain fixed gas costs in order to mitigate the impact on our Members of recovering those costs through the PPFAC (Decision No. 72735, Findings of Fact 8 and 21). Referring to page 1 of Exhibit GEP-2, when the 2011 financial results are adjusted to account for this one-time event, AEPCO net margins exceed $3.8 million and produce a TIER of 1.37 and a DSC of 1.30. Those results are quite comparable to the net margins of $4.1 million, the TIER of 1.38 and the DSC of 1.32 which were authorized by the Commission in our last rate case (Decision No. 72055). They do not support the "experienced 'attrition' in realized returns" which Mr. Vickroy asserts at page 4, lines 20-23, of his direct testimony.

Similarly, as to its 2012 financials, AEPCO recorded roughly $3.975 million of <u>one-time</u> adjustments to recognize a settlement agreement reached in litigation pertaining to California Power Sales, as well as to recognize certain patronage capital allocations from Southwest Transmission Cooperative for 2008 and 2009. Exhibit GEP-2, page 1, shows that, after revising the 2012 data to account for these one-time adjustments, AEPCO would have had net margins of $8.9 million, a TIER of 1.99 and a DSC of 1.51. Those results are substantially above the levels anticipated by the Commission in AEPCO's last rate case.

With regard to Mr. Vickroy's analysis of AEPCO's Funds from Operations ("FFO") to Interest and FFO as a percentage of debt, page 2 of Exhibit GEP-2 shows those strengthened results based on the revised 2011 and 2012 financials I just discussed.

Overall, AEPCO agrees with Mr. Vickroy's testimony on page 12, lines 22-25, that the TIER, DSC, Equity/Total Capitalization and FFO/Interest and FFO/Debt ratios (with or without the above-referenced adjustments) generally place AEPCO within Moody's "A" range for rated G&Ts, as shown on Exhibit REV-3. Given that and the other factors I've discussed, we do <u>not</u> agree with his recommendation of revenues that results in a 1.56 DSC.

Q. On pages 6 and 7 of his testimony, Mr. Vickroy suggests that AEPCO use updated costs of long-term and short-term debt as of December 31, 2012 to calculate its cost of debt. Does the Company have a response?

A. Yes, we do. As an initial matter, referring to page 6, lines 24-26, of Mr. Vickroy's testimony, the Central Bank of Cooperatives debt was paid off on February 1, 2012 and that payoff has already been reflected in the adjustment to interest expense made by AEPCO in its July 2012 filing. In response to Mr. Vickroy's update suggestion, I have prepared

Exhibit GEP-3, which provides the cost of capital for the test year as adjusted and as of December 31, 2012. However, AEPCO continues to believe that the interest expense adjustment proposed in its original filing and which was accepted by Mr. Kalbarczyk is appropriate and should be used by the Commission.

Q. Mr. Vickroy also discusses rating agencies' primary factors in assessing the risk of G&T Cooperatives. Please provide the Company's response.

A. Mr. Vickroy lists five rating factors and their associated Moody's weighting at page 9 of his testimony. In regards to the first factor, Financial Performance and Metrics (40%), AEPCO agrees with his assessment at page 12 that our historical quantitative financial metrics "could qualify [AEPCO] for an investment-grade rating."

The second factor identified by Mr. Vickroy is Long-Term Wholesale Power Supply Contracts/Regulatory Risk (20%). AEPCO disagrees with Mr. Vickroy's statement at page 13 that its partial-requirements member ("PRM") contracts add more risk to AEPCO than other G&Ts with exclusively all-requirements member ("ARM") contracts. To the contrary, the PRM contracts provide <u>greater</u> assurance that AEPCO's fixed costs, as well as its operations and maintenance costs, will be paid by the PRMs regardless of whether they use the capacity or not. Further, AEPCO carries none of the new-build risks associated with any additional capacity resources its PRMs may need now or in the future. For these reasons, AEPCO actually has a <u>lower</u> risk profile than typical G&Ts with exclusively ARM contracts. In response to Mr. Vickroy's concern about the potential ratings impact of rate regulation, AEPCO notes that the Commission's streamlined rate filing rules for cooperatives, which only recently took effect, likely could soften the negative perception which rating agencies admittedly do have regarding rate regulation.

Regarding the third factor, Rate Flexibility/Rate Shock (20%), as I've discussed, AEPCO believes that it is making substantial progress in arriving at a reasonable and workable solution to the EPA's Regional Haze requirements that will (1) significantly mitigate its construction build and rate shock exposure, as well as (2) address Mr. Vickroy's concerns regarding execution of any required construction on a timely and cost-effective basis. On the subject of rate competitiveness, AEPCO has taken significant steps to lower its rates and send more accurate price signals. Specifically, in our last rate case, we revised our rate structure to provide separate energy rates for our Members in order to more accurately reflect the costs associated with base and other resources. In the present rate case, we have proposed (and Liberty has endorsed) revisions to our PPFAC that will further enhance our price signal accuracy and competitiveness. Further, our new lower coal contract prices and rail rates are making us more competitive in the energy market – resulting in a higher utilization of our base resource capacity by our Members and others. Finally, we believe that any concerns about whether AEPCO's rates are competitive are better addressed by granting the Company's request for a revenue decrease rather than holding revenues steady as Mr. Vickroy suggests.

With regard to the rating agencies' last two factors, AEPCO thinks Mr. Vickroy's assessment at page 15 is too negative. For example, in terms of AEPCO's member profile, the National Rural Utilities Cooperative Finance Corporation 2011 Key Performance Indicator for Category 809 (Member Equity as a Percent of Member Capitalization) lists AEPCO's Members' equity average as 40.85%, which is quite close to the nationwide average of 44.15%. On the subject of size, while AEPCO is smaller than many other G&Ts, we also note that Corn Belt Power Cooperative and San Miguel Electric Cooperative are smaller than AEPCO, but, nonetheless, both received "A-" ratings from Standard & Poor's and Fitch in 2011. Therefore, AEPCO does not believe that these factors would necessarily result in an assessment of high risk by rating agencies.

Q. **How does AEPCO's analysis of its risk profile impact its revenue requirements recommendation?**

A. For all of the reasons stated above, AEPCO believes it would rate positively on a number of the quantitative <u>and</u> qualitative criteria. Further, there's no reason to believe that setting rates based upon a 1.32 DSC would result in any rate insufficiency or raise AEPCO's risk profile. Therefore, we continue to recommend that our revenue requirements should be based upon a 1.32 DSC.

Q. **Does AEPCO have a suggestion for an adjustor mechanism, however, which would assist in meeting the capital requirements of whatever environmental compliance strategy AEPCO may develop in the future?**

A. Yes. Assuming the Commission approves our recommendation to set revenues at a 1.32 DSC, AEPCO proposes that an Environmental Compliance Adjustment Rider ("ECAR")

Surcharge be established which would provide a tariff funding mechanism to address the EPA requirements. The ECAR Surcharge would initially be set at zero. When an Environmental Compliance Strategy ("ECS") plan is finalized in accordance with EPA requirements, then AEPCO would file that plan with the Commission in order to establish qualified ECS costs and increase the ECAR Surcharge accordingly. Prior to filing with the Commission, the ECS plan and ECAR Surcharge rate would need AEPCO Board approval and the unanimous consent of AEPCO's Member Distribution Cooperatives. For further details concerning our proposal, my Exhibit GEP-7 is a proposed ECAR Tariff and Exhibit GEP-8 is a plan of administration for the ECAR Surcharge.

RATE BASE — AEPCO REBUTTAL POSITION

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

A. Yes, I have. As discussed later in my testimony, we disagree with certain of Liberty's assertions concerning, among other things, AEPCO's coal inventory levels and depreciation rates. However, to narrow disputed issues in this case, we accept Mr. Kalbarczyk's adjustments solely as they relate to rate base and, therefore, we accept the proposed rate base of $261,075,032, as shown on Table 9 at page 26 of Mr. Kalbarczyk's testimony.

Q. Please provide the Company's response to Mr. Kalbarczyk's testimony regarding AEPCO's request for revised depreciation rates.

A. In the context of his discussion of rate base, Mr. Kalbarczyk incorporates some of the conclusions from Mr. Mazzini's engineering analysis. Specifically, at page 13, Mr. Kalbarczyk states that AEPCO has not laid a proper foundation for its requested depreciation rates because of concerns regarding the useful lives of Apache Station Units ST1, ST2 and ST3. As explained, however, in Mr. Kurtz' rebuttal testimony, the Black & Veatch study correctly confirmed the useful lives of these units. Furthermore, the study was conducted in order to conform to Rural Utilities Service requirements for establishing depreciation rates. Accordingly, although we do not dispute Mr. Kalbarczyk's depreciation-related adjustment to rate base, we continue to believe that Commission approval of our revised depreciation rates is appropriate.

OPERATING INCOME — AEPCO REBUTTAL POSITION

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

A. AEPCO is proposing rebuttal adjustments for wheeling expense and gas legal costs, which result in rebuttal proposed test year revenues of about $159.3 million, operating expenses of $148.6 million, electric operating income (margins) of approximately $10.7 million and a net margin of slightly less than $2.0 million. For ease of reference, my Exhibit GEP-4 provides a summary and comparison of AEPCO's original rate filing requests, Staff's direct testimony position and AEPCO's rebuttal position.

Q. Please describe the wheeling expense rebuttal adjustment that AEPCO is proposing.

A. AEPCO has several contracts with the Western Area Power Administration under which it receives point-to-point transmission service. The Parker Davis point-to-point transmission service rates increased on October 1, 2012. This caused a $76,800 increase in AEPCO annual expenses. Further, the Intertie point-to-point transmission service rates were increased on May 1, 2013, resulting in an additional $163,200 in expenses. These combine for a total rebuttal adjustment of $240,000 in additional operating expenses.

Q. Please describe the gas legal costs adjustment that AEPCO is proposing.

A. During the course of discovery, AEPCO noticed that natural gas legal expenses that should have been reclassified to administrative & general expenses had not been reclassified in the original filing. Therefore, AEPCO proposes as a rebuttal adjustment to reclassify approximately $260,000 of expenses from fuel expenses to administrative & general expense. The net effect of this rebuttal adjustment is a zero increase in operating expenses.

Q. At page 22 of his testimony, Mr. Kalbarczyk commented on the characterization of two of AEPCO's pro forma adjustments. Do you have a response?

A. Yes, I do. Mr. Kalbarczyk questioned AEPCO's characterization of its maintenance outage overhaul adjustment and its rate case expense adjustment. He is correct that AEPCO does not propose to establish a regulatory asset to collect either maintenance outage overhaul or rate case expenses. Instead, AEPCO agrees with the characterization of these adjustments as normalization adjustments. Further, AEPCO agrees that its rate case expense adjustment should be based upon more timely and updated cost information. In that regard, AEPCO will furnish an updated rate case cost estimate to Staff later this month. This will include (1) actual incurred expenses through mid-June, plus (2) an estimate of the additional expenses necessary to process this case to decision issuance by the Commission.

Q. Have you prepared exhibits that summarize AEPCO's current positions and requests?

A. Yes, I have. As I mentioned before, Exhibit GEP-4 summarizes AEPCO's original rate filing, Staff's direct testimony and AEPCO's rebuttal positions. In support of this exhibit, we have developed rebuttal Schedules A through H, copies of which are being delivered to Staff at the time this testimony is filed. As reflected on page 1 of Exhibit GEP-4, AEPCO proposes the Commission authorize a reduction in its revenues of approximately $4.3 million as opposed to Staff's proposal of no change to current revenues. Page 2 of Exhibit GEP-4 compares Staff's and AEPCO's rate base positions. Its page 3 details the operating income recommendations and page 4 provides our proposed rebuttal adjustments.

FUEL AND PURCHASED POWER — AEPCO REBUTTAL POSITION

Q. Have you reviewed the direct testimony of Staff witness Mr. Antonuk?

A. Yes, I have. Attached to Mr. Antonuk's testimony is a report that reviews AEPCO's fuel, purchased power and plant operations policies, activities and costs. Overall, Liberty's review is positive and we agree with many of the report's findings. Specifically, we agree with Liberty's conclusions that: the reduction in our contract for natural gas storage services was reasonable and the proper adjustment was made to our costs in relation to it (page 7); AEPCO effectively procured short-term contract coal deliveries at favorable prices in 2012 (page 19); we achieved very favorable results through our challenge of rail rates before the Surface Transportation Board ("STB"), which opened up new coal supply origins (page 20); we took a significant positive step in 2012 in relation to our long-term coal inventory management (page 21); and our transfer of trading operations to ACES Power Marketing has resulted in effective scheduling and dispatching at a lower cost (pages 28-29).

Q. In the Coal section of its report, Liberty raises some concerns about AEPCO's coal procurement and inventory management in 2012. Does the Company have a response to these concerns?

A. We do. Attached to my testimony as Exhibit GEP-5 is a report prepared by Emily Regis, AEPCO's Fuels Resource Administrator. As explained in greater detail in Ms. Regis' report, we disagree with Liberty's negative view of AEPCO's decision to make short-term coal purchases in 2012 rather than utilizing our existing inventory of premium high-Btu/lb, low-sulfur coal. This decision, based on the analysis of our Coal Supply Group (of which I am a member), was part of a larger strategy to leverage AEPCO's inventory and the very favorable STB rail rates decision to achieve a substantially lower delivered cost of fuel and reliable supply options for the benefit of our Members going forward. I am pleased to report that the strategy was successful. AEPCO was able to take advantage of low natural gas prices, the STB decision and its inventory in order to delay contract negotiations while coal blend testing was ongoing. As a result, AEPCO now has competitive rail access to coal suppliers, as well as the opportunity to purchase high-quality coal at reduced delivered prices. Also, AEPCO is currently implementing a plan to decrease its coal inventory to achieve compliance with its target levels without sacrificing operational reliability and its ability to remain environmentally compliant. In response to Liberty's recommendation that AEPCO reevaluate its coal consumption forecasting, Ms. Regis notes that AEPCO has updated its forecasts and provides more detail on that subject at page 2 of Exhibit GEP-5.

Q. On pages 26-28 of its report, Liberty discusses certain scheduling and trading issues for PRMs and their impacts on AEPCO. Does the Company have a response on these issues?

A. Yes. I would note that, pursuant to agreement, AEPCO started providing scheduling and trading services on February 1, 2013 to Mohave Electric Cooperative. In addition, pursuant to a similar agreement, AEPCO started providing scheduling and trading services on June 1, 2013 to Sulphur Springs Valley Electric Cooperative.

PPFAC MECHANISM — AEPCO REBUTTAL POSITION

Q. Mr. Pierson, the Liberty report attached to Mr. Antonuk's direct testimony also addressed AEPCO's PPFAC. Is that correct?

A. Yes. On pages 34-36 of its report, among other issues, Liberty confirmed that AEPCO has been administering the clause correctly and in conformance with Commission directives. Also, on page 36, Liberty found reasonable and appropriate AEPCO's proposed modifications to the PPFAC, the continuance of the efficacy clause and the closeout of the bank balances under the current clause. Accordingly, we would request that the Commission authorize each of those items in its decision as summarized at pages 26-27 of my direct testimony.

Q. Do you have any clarifications regarding AEPCO's proposed modifications of the PPFAC?

A. Yes, I do. First, I have a slight clarification to my direct testimony concerning AEPCO's proposed modification to separate the bank balances from the fuel adjustor rates. Specifically, the balances would be recovered or refunded through a *continuing* six-month amortization tariff rider and not a "temporary" rider, as stated in my direct testimony. Second, in response to Liberty's concerns about including carbon taxes and Cap and Trade Allowances in the PPFAC, AEPCO withdraws its request that they should be included in the PPFAC.

Q. When does AEPCO recommend that the first semi-annual adjustor take effect under the new PPFAC and how will it be calculated?

A. Consistent with current practice, we recommend that the first semi-annual fuel adjustor be filed on March 1, 2014, to become effective on April 1, 2014. That initial filing will be based upon data covering the 12 months ended December 31, 2013. Thereafter, AEPCO would make fuel adjustor filings on March 1 and September 1, to become effective on April 1 or October 1, based upon historical periods of the prior 12 months ended December 31 or June 30, respectively.

RATE DESIGN — AEPCO REBUTTAL POSITION

Q. Have you reviewed the direct rate design testimony Mr. Kalbarczyk filed on Staff's behalf on April 22, 2013?

A. Yes, I have. We agree with Staff on rate design, although our proposed rates differ due to our differing positions on the appropriate DSC level, *i.e.*, AEPCO at 1.32 and Staff at 1.56. In addition, we recommend including the rebuttal adjustment regarding the additional wheeling expenses that I explained earlier in my testimony. Further, AEPCO noted during the discovery process that in its original filing on Schedule G-6, page 2, Production – Fuel, Acct. 547 had been overstated by approximately $791,000 and Production Fuel, Acct. 501 had been understated by the same amount. AEPCO has made that correction in the calculation of its proposed rebuttal rates. My Exhibit GEP-6 summarizes AEPCO's current rates, its filed rates, Staff's proposed rates and AEPCO's proposed rates on rebuttal. Exhibit GEP-6 also contains a proof of revenue.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

EXHIBIT GEP-2

Arizona Electric Power Cooperative, Inc.
Computation of Various Financial Ratios
Sources: RUS Form 12
Twelve Months Ended December 31, 2011 and 2012

Description	RUS FORM 12 12 Mos. Ended 12/31/11	2011 Write-offs	Adjusted for Write-offs 12/31/11	RUS FORM 12 12 Mos. Ended 12/31/12	2012 Write-offs	Adjusted for Write-offs 12/31/12
Times Interest Earned Ratio Calculation:						
Net Patronage Capital or Margins	$ 1,855,188	$ 1,998,000	$ 3,853,188	$ 4,966,107	$ 3,974,691	$ 8,940,798
Interest on Long-Term Debt	10,518,102	-	10,518,102	9,075,209	-	9,075,209
Total	$ 12,373,290	$ 1,998,000	$ 14,371,290	$ 14,041,316	$ 3,974,691	$ 18,016,007
Times Interest Earned Ratio	1.18		1.37	1.55		1.99
Debt Service Coverage Ratio Calculation:						
Net Patronage Capital or Margins	$ 1,855,188	$ 1,998,000	$ 3,853,188	$ 4,966,107	$ 3,974,691	$ 8,940,798
Depreciation & Amortization Expense	9,951,210	-	9,951,210	10,172,982	-	10,172,982
Interest on Long-Term Debt	10,518,102	-	10,518,102	9,075,209	-	9,075,209
Total	$ 22,324,500	$ 1,998,000	$ 24,322,500	$ 24,214,298	$ 3,974,691	$ 28,188,989
Principal Payments	$ 8,177,084	$ -	$ 8,177,084	$ 9,589,123	$ -	$ 9,589,123
Interest on Long Term Debt	10,518,102	-	10,518,102	9,075,209	-	9,075,209
Total	$ 18,695,186		$ 18,695,186	$ 18,664,332		$ 18,664,332
Debt Service Coverage Ratio	1.19		1.30	1.30		1.51

Arizona Electric Power Cooperative, Inc.
Computation of Various Financial Ratios
Sources: RUS Form 12
Twelve Months Ended December 31, 2011 and 2012

Description	RUS FORM 12 12 Mos. Ended 12/31/11	2011 Write-offs	Adjusted for Write-offs 12/31/11	RUS FORM 12 12 Mos. Ended 12/31/12	2012 Write-offs	Adjusted for Write-offs 12/31/12
Fund From Operations/ Interest on Long Term Debt:						
Operating Margins	$ 829,142	$ 1,998,000	$ 2,827,142	$ 6,934,483	$ 3,974,691	$ 10,909,174
Plus:						
Interest on Long Term Debt	10,518,102	-	10,518,102	9,075,209	-	9,075,209
Depreciation and Amortization	9,951,210	-	9,951,210	10,172,982	-	10,172,982
Funds From Operations	$ 21,298,454	$ 1,998,000	$ 23,296,454	$ 26,182,674	$ 3,974,691	$ 30,157,365
Interest on Long Term Debt	$ 10,518,102	$ -	$ 10,518,102	$ 9,075,209	$ -	$ 9,075,209
FFO/Interest	2.02		2.21	2.89		3.32
Long Term Debt (Including Current Portion)	$ 225,476,378	$ -	$ 225,476,378	$ 187,110,195	$ -	$ 187,110,195
Obligations Under Capital Lease (Including Current Portion)	2,563,182	-	2,563,182	1,075,072	-	1,075,072
Notes Payable	3,721,518	-	3,721,518	4,067,238	-	4,067,238
Total Debt	$ 231,761,078	$ -	$ 231,761,078	$ 192,252,505	$ -	$ 192,252,505
FFO/Debt	9.19%		10.05%	13.62%		15.69%

EXHIBIT GEP-3

Arizona Electric Power Cooperative, Inc.
Cost of Long Term and Short Term Debt

Line No.	Description	Col. 1 Debt Outstanding $	Col. 2 Interest Rate %	Col. 3 Annual Interest $
1	As of December 31, 2011 - As Adjusted			
2	Long Term Debt:			
3	FFB Debt (1)	$ 154,050,527	5.140%	$ 7,918,197
4	CFC Series 1994A Bonds	13,484,574	1.000%	134,846
5	NRUCFC	33,965,012	3.350%	1,137,828
6	Regulatory Asset	-		91,000
7	Subtotal	201,500,113	4.606%	9,281,871
8	Short Term Debt	3,721,518	0.377%	14,030
9	Total	$ 205,221,631	4.530%	$ 9,295,901
10				
11	As of December 31, 2012			
12	Long Term Debt:			
13	FFB Debt - (2)	$ 167,875,727	4.792%	$ 8,044,469
14	CFC Series 1994A Bonds	12,810,345	0.650%	83,267
15	NRUCFC	16,531,153	3.433%	567,525
16	Regulatory Asset			91,000
17	Subtotal	197,217,225	4.455%	8,786,261
18	Short Term Debt	4,067,238	0.823%	33,477
19	Total	$ 201,284,463	4.382%	$ 8,819,738
20				
21				
22	(1) Balance reflects 4th Quarter debt service payment made on January 3, 2012.			
23	(2) Balance reflects 4th Quarter debt service payment made on January 1, 2013.			

EXHIBIT GEP-4

Arizona Electric Power Cooperative, Inc.

Comparison of Increase in Gross Revenue Requirement

Test Year Ended December 31, 2011

Line No.	Description	Col. A Company As Filed Position	Col. B Staff Direct Position	Col. C Company Rebuttal Position
1	Summary of Revenue Increase Proposed:			
2	Proposed Revenue Increase	$ (4,527,467)	$ -	$ (4,287,465)
3	Revenues in Test Year - Present Rates	$ 154,924,873	$ 154,924,871	$ 154,924,871
3	Revenue Increase Percentage	-2.92%	0.00%	-2.77%
4				
5	Pro Forma Statement of Operations			
6	with Proposed Rates:			
7	Operating Revenues	$ 159,097,135	$ 163,624,600	$ 159,337,135
8	Operating Expense	148,420,479	148,420,479	148,660,479
9	Electric Operating Margins	10,676,656	15,204,121	10,676,656
10	Interest & Other Deductions	9,745,481	9,745,481	9,745,481
11	Operating Margins	931,175	5,458,640	931,175
12	Non-Operating Margins	1,026,046	1,026,046	1,026,046
13	Net Patronage Capital or Margins	$ 1,957,221	$ 6,484,686	$ 1,957,221
14				
15	Times Interest Earned Ratio:			
16	Net Patronage Capital or Margins	$ 1,957,221	$ 6,484,686	$ 1,957,221
17	Interest on Long Term Debt	9,281,871	9,281,871	9,281,871
18	Total	$ 11,239,092	$ 15,766,557	$ 11,239,092
19	Times Interest Earned Ratio	1.21	1.70	1.21
20				
21	Debt Service Coverage Ratio:			
22	Net Patronage Capital or Margins	$ 1,957,221	$ 6,484,686	$ 1,957,221
23	Depreciation & Amortization	13,349,504	13,349,504	13,349,504
24	Interest on Long Term Debt	9,281,871	9,281,871	9,281,871
25	Total	$ 24,588,596	$ 29,116,061	$ 24,588,596
26				
27	Interest on Long Term Debt	$ 9,281,871	$ 9,281,871	$ 9,281,871
28	Principal Payments	9,345,853	9,345,853	9,345,853
29	Debt Service	$ 18,627,724	$ 18,627,724	$ 18,627,724
30	Debt Service Coverage Ratio	1.32	1.56	1.32
31				
32	Return on Fair Value Rate Base:			
33	Electric Operating Margins	$ 10,676,656	$ 15,204,121	$ 10,676,656
34	Rate Base	$ 267,463,587	$ 261,075,032	$ 261,075,032
35	Return on Fair Value Rate Base	3.99%	5.82%	4.09%
36				
37	References:			
38	Column A: Company Original Filed Schedules			
39	Column B: Staff Direct Testimony and Schedules			
40				

Arizona Electric Power Cooperative, Inc.
Comparison of Increase in Gross Revenue Requirement
Test Year Ended December 31, 2011

RATE BASE - ORIGINAL COST

LINE NO.		Col. A COMPANY AS FILED	Col. B STAFF DIRECT POSITION	Col. C COMPANY REBUTTAL POSITION
1	Plant in Service	$ 452,690,894	$ 452,690,894	$ 452,690,894
2	Less: Acc. Depreciation & Amortization	(219,978,356)	(216,580,062)	(216,580,062)
3	Net Plant in Service	232,712,538	236,110,832	236,110,832
4				
5	*LESS:*			
6				
7	Customer Advances for Construction	-	-	-
8				
9	Contributions in Aid of Construction	-	-	-
10				
11	*ADD:*			
12				
13	Working Capital	34,751,049	24,964,200	24,964,200
14				
15	Plant Held for Future Use	-	-	-
16				
17	Deferred Debits	-	-	-
18				
19	Total Rate Base	$ 267,463,587	$ 261,075,032	$ 261,075,032

References:
Column A: Company Schedule B-1, Page 1
Column B: Kalbarczyk Direct Testimony

Arizona Electric Power Cooperative, Inc.
Comparison of Increase in Gross Revenue Requirement
Test Year Ended December 31, 2011

OPERATING INCOME - TEST YEAR, STAFF ADJUSTED AND COMPANY PROPOSED

Line No.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR AS ADJUSTED	[C] COMPANY REBUTTAL TEST YEAR ADJUSTMENTS	[D] COMPANY REBUTTAL TEST YEAR AS ADJUSTED	[E] COMPANY REBUTTAL PROPOSED CHANGES	[F] COMPANY REBUTTAL RECOMMENDED
	REVENUES:						
1	Class A Member Electric Revenue	154,924,871	154,924,871	-	154,924,871	(4,287,465)	150,637,406
2	Non-Class A, Non-Firm, & Non-Member	2,903,085	2,903,085	-	2,903,085	-	2,903,085
3	Total Electric Revenue	157,827,956	157,827,956	-	157,827,956	(4,287,465)	153,540,491
4	Other Operating Revenue	5,796,644	5,796,644	-	5,796,644	-	5,796,644
5	Total Revenues	163,624,600	163,624,600	-	163,624,600	(4,287,465)	159,337,135
6							
7	*EXPENSES:*						
8	Operations - Production, Fuel	65,283,413	65,283,413	(260,271)	65,023,142	-	65,023,142
9	Operations - Production, Steam	9,457,512	9,457,512	-	9,457,512	-	9,457,512
10	Operations - Production, Other	337,128	337,128	-	337,128	-	337,128
11	Operations - Other Pwr Supply, Demand	3,791,951	3,791,951	-	3,791,951	-	3,791,951
12	Operations - Other Pwr Supply - Energy	13,533,831	13,533,831	-	13,533,831	-	13,533,831
13	Operations - Other Power Supply - System Control & Other	3,584,820	3,584,820	-	3,584,820		3,584,820
14	Operations - Transmission	12,379,664	12,379,664	240,000	12,619,664	-	12,619,664
15	Operations - Administrative and General	8,516,626	8,516,626	260,271	8,776,897	-	8,776,897
16	Maintenance - Production, Steam	13,588,254	13,588,254	-	13,588,254	-	13,588,254
17	Maintenance - Production, Other	1,157,455	1,157,455	-	1,157,455	-	1,157,455
18	Maintenance - Transmission	3,191	3,191	-	3,191	-	3,191
19	Maintenance - General Plant	1,167,443	1,167,443	-	1,167,443	-	1,167,443
20	Depreciation and Amortization	13,349,504	13,349,504	-	13,349,504	-	13,349,504
21	Taxes	2,269,687	2,269,687	-	2,269,687	-	2,269,687
22	Total Operating Expenses	148,420,479	148,420,479	240,000	148,660,479	-	148,660,479
23							
24	Electric Operating Margins	15,204,121	15,204,121	(240,000)	14,964,121	(4,287,465)	10,676,656
25							
26	*INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS:*						
27	Interest on Long-term Debt	9,281,871	9,281,871	-	9,281,871	-	9,281,871
28	Other Interest & Other Deductions	463,610	463,610	-	463,610	-	463,610
29	Total Interest & Other Deductions	9,745,481	9,745,481	-	9,745,481	-	9,745,481
30							
31	*OPERATING MARGINS*	5,458,640	5,458,640	(240,000)	5,218,640	(4,287,465)	931,175
32							
33	*NON-OPERATING MARGINS*						
34	Interest Income	438,715	438,715	-	438,715	-	438,715
35	Other Non-operating Income	587,331	587,331	-	587,331	-	587,331
36	Total Non-Operating Margins	1,026,046	1,026,046	-	1,026,046	-	1,026,046
37							
38	*EXTRAORDINARY ITEMS*	-	-	-	-	-	-
39							
40	*NET MARGINS (LOSS)*	$ 6,484,686	$ 6,484,686	$ (240,000)	$ 6,244,686	$ (4,287,465)	$ 1,957,221
41							
42							
43	References:						
44	Column [A]: Company Original Filed Schedules						
45	Column [B]:Staff Direct Testimony and Schedules						
46							

Arizona Electric Power Cooperative, Inc.
Rebuttal Adjustments
Twelve Months Ended December 31, 2011

Description	$	$
1. Adjustment to annualize rate increases in Western Wheeling Contracts:		
Western Area Power Contract Rate Increases:		
Parker Davis PTP Firm Transmission	$76,800	
Intertie PTP Firm Transmission	163,200	
Total		$240,000
2. Adjustments to reclassify legal expenses from Fuel to Administrative & General Expense		
Fuel Expense	(260,271)	
Administrative & General Expense	260,271	
Total		-
Total Adjustments to Expense		$240,000

EXHIBIT GEP-5

<u>Report in Response to Liberty Consulting Group Direct Testimony of John Antonuk</u>

by

Emily Regis, Fuels Resource Administrator

Exhibit GEP-5

(Public Version)

On May 1, 2013, John Antonuk of Liberty Consulting Group submitted Direct Testimony in AEPCO's rate case before the Arizona Corporation Commission, Docket No. E-01773A-12-0305. Attached to Mr. Antonuk's testimony as Exhibit JEA-2 is a report summarizing Liberty's examination of the prudence of AEPCO's fuel, purchased power, and plant operations policies, activities, and costs. Many of Liberty's findings are complimentary of AEPCO. However, the report raises concerns about AEPCO's coal forecasting, procurement and inventory in 2012. The purpose of this report is to respond to those particular conclusions and associated recommendations.

I. <u>Coal Supply Group</u>

As indicated in the Liberty report, AEPCO uses a team of Cooperative employees called the Coal Supply Group to develop its coal supply and coal transportation strategies. The Group was formed in 2006 and meets regularly to review various supply and transportation options as well as to decide on the direction of coal procurement, coal transportation and coal inventory management activities. This team is comprised of a cross-section of managers and administrators from several departments, including the following positions: Executive Vice President and Chief Executive Officer, Corporate Counsel, Director of Power Production, Fuels Resource Administrator, Director of Engineering, Director of Energy Services, Chief Financial Officer, Manager of Cost Accounting and Manager of Financial Services. Other Cooperative staff participate when a specific need arises, including the Director of Environmental Services. Copies of the Group's various analyses are maintained in the Cooperative's files and specific action items are given to appropriate individuals.

II. <u>Coal Consumption Forecasting</u>

In 2011, AEPCO's coal and energy market intelligence consultant, ACES, began providing the Cooperative's coal consumption forecasts. These forecasts project coal consumption based on various inputs including expected member loads, natural gas and coal prices as well as projected energy market prices. The forecasts are provided to assist AEPCO in its budgetary and coal purchase planning activities several months in advance of the next calendar year. The Coal Supply Group considers the forecasts among a variety of other information in making procurement and inventory management decisions. Periodically, the Group reviews and evaluates the forecast in light of changed circumstances and adjusts AEPCO's strategy accordingly.

On page 21 of its report, Liberty states that in 2010 and 2011, AEPCO data showed a reasonable correlation between forecast and actual coal consumption. However, in 2012, the report notes that AEPCO's actual coal consumption was 30% higher than the forecast. This was caused in part by the fact that actual natural gas prices differed greatly from the expectations set in 2011. Additionally, as explained in greater detail below, AEPCO successfully lowered its actual delivered coal cost, thereby making coal a more economically advantageous resource than had been originally forecast. Finally, AEPCO notes that the 2012 forecast was the first forecasting effort performed and provided by ACES. In all, AEPCO believes that the 2012 mismatch was an abnormality for various reasons and was inconsistent with its historical practice of accurate forecasting.

Liberty's report recommends that AEPCO reevaluate its forecasting of coal consumption to improve the match between forecasts and actual coal consumption. Per our established practice, AEPCO has updated its forecasts with more recent energy and fuel resource information that appears to follow more normal historic trends. AEPCO anticipates a higher consumption of fuel by its coal units moving forward, but will continue to monitor its coal inventory levels and fuel supply options in order to maintain the lowest cost fuel supply for its members. Additionally, AEPCO will continue to evaluate the process by which the forecasts are developed and will closely monitor the forecasts in the future.

III. 2012 Coal Procurement and Inventory

Liberty's report contains two separate, but related, conclusions regarding AEPCO's coal procurement and inventory in 2012. First on page 21, Liberty criticizes AEPCO's decision to make short-term coal purchases for use in 2012 instead of using the coal in its pre-existing inventory. Second, on page 22, Liberty notes that more than half of AEPCO's coal inventory in 2012 consisted of [redacted] coal which has been stockpiled since 2008. Taken together, Liberty contends that AEPCO should have used the [redacted] coal in 2012 to further reduce the stockpile and bring AEPCO into compliance with its target inventory levels.

As explained below, the coal purchases and deviation from target inventory levels in 2012 were part of a larger strategy developed by the Coal Supply Group to leverage AEPCO's inventory and the very favorable and somewhat unexpected late-2011 Surface Transportation Board ("STB") rail rates decision to achieve a substantially lower delivered cost of fuel and reliable supply options for the benefit of its members going forward.

The background of the Coal Supply Group's strategy starts with AEPCO's limited access to fuel markets. Due to its small size and geographic location, as well as its [redacted] AEPCO's historic ability to respond to opportunities in fuel markets has been very restricted. In 2011, AEPCO was in the last year of a three year coal supply agreement with Peabody COALSALES ("Peabody") for the purchase of coal from Peabody's El Segundo and Lee Ranch Mines in New Mexico at a delivered cost of approximately [redacted]. AEPCO burned this [redacted] coal as its primary fuel for three years. During this time, we held in reserve a stockpile of the [redacted] coal, which (as Liberty notes in its report) is a premium high Btu/lb, low sulfur coal and, therefore, is very expensive for AEPCO to obtain. [redacted] AEPCO has kept this coal in reserve to provide operational reliability and assure environmental compliance for Apache Station.

Over the years, AEPCO has attempted on several occasions to improve its access to the various fuel markets by challenging rail transportation rates. In late 2008, AEPCO tried again by filing a rate complaint against BNSF Railway before the STB. In November 2011, the STB issued a very favorable decision in which it (among other relief) established maximum lawful rates applicable to AEPCO through 2018. The STB's rate prescriptions opened competitive markets for AEPCO among coal suppliers and the railroads.

In particular, the STB ruling gave AEPCO access to coal [redacted] that previously had been cost prohibitive for AEPCO because of the high transportation rates. Access to [redacted] coal was significant because, prior to 2012, AEPCO had conducted extensive research with outside engineering consultants regarding operational issues associated with burning a blend of [redacted] coal at Apache Station. These studies showed that AEPCO would have a high level of success with blending [redacted] coal [redacted] and that (if transportation costs could be managed) this blend would provide [redacted] benefits at a low delivered cost. With the new access the STB ruling facilitated, AEPCO secured two test trains of [redacted] coal and began a series of test burns of various blends of [redacted] coal with the [redacted]

While running these test burns in early 2012, AEPCO unexpectedly was also able to take advantage of the low cost of natural gas and its coal inventory to delay executing new coal supply contracts and by doing so acquired more time to negotiate lower prices with both coal suppliers and the railroads. Specifically, AEPCO utilized the published rate prescriptions for BNSF [redacted] coal origins to negotiate with Union Pacific Railroad ("UP"). The result was a competitively priced coal transportation agreement for UP's [redacted] coal supply origins for [redacted]. After confirming this coal transportation agreement with UP, AEPCO then secured 300,000 tons of [redacted] coal for delivery between April and December 2012. Access to [redacted] also gave AEPCO leverage in negotiations with its [redacted] supplier. In March 2012, AEPCO entered into an agreement to purchase 300,000 tons of [redacted] coal [redacted] at a delivered cost [redacted] lower than the previous [redacted] agreement. By using its leverage to negotiate these short term purchases, AEPCO projected to lower its average delivered cost [redacted] and Liberty's report at pages 19-20 confirms the success of AEPCO's contract negotiations. As an added bonus, by burning 3,194,468 Dth of natural gas in the coal units between January and June, AEPCO was able to realize and pass on to its Member Distribution Cooperatives an additional $1.166 million in savings.

As Liberty notes in its report, as a result of these coal purchases as well as the use of natural gas (i.e., reduced coal burning) in early 2012, AEPCO's coal inventory levels increased between March 2012 and July 2012. However, this increase was in part a timing issue because AEPCO elected to start coal shipments at the end of March in order to maintain a ratable monthly delivery schedule and allow time for AEPCO's unit train to complete the delivery cycles. AEPCO's estimated cycle time for delivery of [redacted] coal supply is 7-9 days while its [redacted] coal transportation cycle time is an estimated 3-5 days. By starting the shipments early in March 2012, AEPCO was able to maximize the use of its single unit train and limit the need to lease additional train sets. AEPCO obtained a trip-lease train from another utility for four trips from the [redacted] mines in 2012 and utilized its unit train for all the other shipments.

While AEPCO's coal inventory increased during the March-to-July timeframe, these coal deliveries were not intended to and did not add to the stockpile. As Liberty notes at page 10 of its report, AEPCO's coal deliveries in 2012 fell significantly below its 2010 and 2011 delivery levels. Further, as Liberty's chart at page 17 indicates, AEPCO's coal inventory at the end of 2012 was roughly the same as 2011. The reason for this is that AEPCO actually used these short term coal purchases to meet its operational needs and [redacted]

Because AEPCO had limited experience blending [redacted] coals, the [redacted] coal was held in the stockpile for the remainder of 2012 to meet any reliability and operational needs that may have arisen. Based on its 2012 efforts and successes, AEPCO was able to achieve a consistent blend of [redacted] coal such that the Coal Supply Group approved plans to start consuming the [redacted] coal inventory in 2013.

Since early 2013, AEPCO has decreased its coal inventory from approximately [redacted] at the end of 2012, to about [redacted] as of the end of April 2013. AEPCO expects to continue to consume its existing inventory supplemented with spot coal supply purchases through 2013. Summer 2013 projections for coal consumption at Apache Station (May through September) are higher due to the lower cost of delivered coal and, correspondingly, the lower expected cost of our coal-fired electricity. Based on a conservative estimate of consumption, we believe AEPCO will be close to returning to its target coal inventory level by the end of 2013.

At page 22 of its report, Liberty recommends that AEPCO manage its coal inventory more aggressively and specifically reevaluate its inventory of [redacted] coal. Consistent with that and as discussed, the Coal Supply Group's decisions in 2012 were part of a larger strategy to use the November 2011 STB decision to place AEPCO in a better position to decrease its reliance on the [redacted] reserve. This strategy was successful. AEPCO now has competitive rail access to coal suppliers in the [redacted] and is no longer captive [redacted]. AEPCO is decreasing its inventory to achieve compliance with its target levels. But, this was made possible because AEPCO had sufficient inventory in 2012 to fuel its units while agreements were negotiated and coal blend testing was conducted. This leverage enabled AEPCO to delay entering any coal supply and coal transportation agreements until it could be assured competitive deals were struck.

EXHIBIT GEP-6

Arizona Electric Power Cooperative, Inc.
Comparison of Proposed Rates & PPFAC Bases and Proof of Revenues
Test Year Ended December 31, 2011

Line	Description	Col. 1 Company Current Rates	Col. 2 Company As Filed Position	Col. 3 Staff Direct Position	Col. 4 Company Rebuttal Position
1	Collective All-Requirements Members: (1)				
2	Fixed Charge - $/Month	$ 273,334	$ 280,598	$ 320,713	$ 280,682
3	O&M Charge - $/Month	$ 414,019	$ 458,175	$ 458,175	$ 462,845
4	Energy Rates:				
5	Base Resources $/kWh	$ 0.03132	$ 0.02921	$ 0.02921	$ 0.02958
6	Other Existing Resources $/kWh	$ 0.05300	$ 0.04795	$ 0.04795	$ 0.03904
7	PPFAC Bases:				
8	PPFAC-Base Resources Base - Per kWh	$ 0.03513	$ 0.02921	$ 0.02921	$ 0.02958
9	PPFAC-Other Resources Base - Per kWh	$ 0.07188	$ 0.04795	$ 0.04795	$ 0.03904
10	PPFAC-Fixed Fuel Costs Base - Per Month	$ -	$ 180,956	$ 180,956	$ 183,236
11	Revenues Generated	$ 16,903,585	$ 16,684,166	$ 17,165,549	$ 16,630,822
12	Revenue Increase over Current Rates		$ (219,419)	$ 261,964	$ (272,763)
13	Percentage Increase (Decrease)		-1.30%	1.55%	-1.61%
14					
15	Partial-Requirements Members:				
16	Mohave Electric Cooperative				
17	Fixed Charge - $/Month	$ 835,756	$ 856,355	$ 978,782	$ 856,617
18	O&M Charge - $/Month	$ 1,274,882	$ 1,419,059	$ 1,419,059	$ 1,433,723
19	Energy Rates:				
20	Base Resources $/kWh	$ 0.03191	$ 0.02894	$ 0.02894	$ 0.02931
21	Other Existing Resources $/kWh	$ 0.05852	$ 0.05437	$ 0.05437	$ 0.04118
22	PPFAC Bases:				
23	PPFAC-Base Resources Base - Per kWh	$ 0.03454	$ 0.02894	$ 0.02894	$ 0.02931
24	PPFAC-Other Resources Base - Per kWh	$ 0.06191	$ 0.05437	$ 0.05437	$ 0.04118
25	PPFAC-Fixed Fuel Costs Base - Per Month	$ -	$ 542,273	$ 542,273	$ 549,433
26	Revenues Generated	$ 50,184,760	$ 46,950,488	$ 48,419,615	$ 47,374,155
27	Revenue Increase over Current Rates		$ (3,234,272)	$ (1,765,145)	$ (2,810,605)
28	Percentage Increase (Decrease)		-6.44%	-3.52%	-5.60%
29					

Arizona Electric Power Cooperative, Inc.
Comparison of Proposed Rates & PPFAC Bases and Proof of Revenues
Test Year Ended December 31, 2011

Line	Description	Col. 1 Company Current Rates	Col. 2 Company As Filed Position	Col. 3 Staff Direct Position	Col. 4 Company Rebuttal Position
1	Sulphur Springs Valley Electric Cooperative				
2	Fixed Charge - $/Month	$ 740,041	$ 758,281	$ 866,687	$ 758,513
3	O&M Charge - $/Month	$ 1,128,876	$ 1,256,541	$ 1,256,541	$ 1,269,525
4	Energy Rates:				
5	Base Resources $/kWh	$ 0.03205	$ 0.02938	$ 0.02938	$ 0.02975
6	Other Existing Resources $/kWh	$ 0.05742	$ 0.05109	$ 0.05109	$ 0.04139
7	PPFAC Bases:				
8	PPFAC-Base Resources Base - Per kWh	$ 0.03449	$ 0.02938	$ 0.02938	$ 0.02975
9	PPFAC-Other Resources Base - Per kWh	$ 0.06449	$ 0.05109	$ 0.05109	$ 0.04139
10	PPFAC-Fixed Fuel Costs Base - Per Month	$ -	$ 480,169	$ 480,169	$ 486,509
11	Revenues Generated	$ 47,411,111	$ 45,317,701	$ 46,618,576	$ 45,736,988
12	Revenue Increase over Current Rates		$ (2,093,410)	$ (792,535)	$ (1,674,122)
13	Percentage Increase (Decrease)		-4.42%	-1.67%	-3.53%
14					
15	Trico Electric Cooperative				
16	Fixed Charge - $/Month	$ 710,367	$ 743,828	$ 850,168	$ 743,980
17	O&M Charge - $/Month	$ 764,465	$ 859,840	$ 859,840	$ 868,482
18	Energy Rates:				
19	Base Resources $/kWh	$ 0.03214	$ 0.02947	$ 0.02947	$ 0.02984
20	Other Existing Resources $/kWh	$ 0.05747	$ 0.04219	$ 0.04219	$ 0.03747
21	PPFAC Bases:				
22	PPFAC-Base Resources Base - Per kWh	$ 0.03431	$ 0.02947	$ 0.02947	$ 0.02984
23	PPFAC-Other Resources Base - Per kWh	$ 0.08274	$ 0.04219	$ 0.04219	$ 0.03747
24	PPFAC-Fixed Fuel Costs Base - Per Month	$ -	$ 569,977	$ 569,977	$ 574,197
25	Revenues Generated	$ 40,425,414	$ 41,445,050	$ 42,721,131	$ 40,895,440
26	Revenue Increase over Current Rates		$ 1,019,636	$ 2,295,717	$ 470,026
27	Percentage Increase (Decrease)		2.52%	5.68%	1.16%
28					
29	Total Revenues Generated	$ 154,924,871	$ 150,397,405	$ 154,924,871	$ 150,637,406
30	Total Revenue Increase over Current Rates		$ (4,527,466)	$ 0	$ (4,287,465)
31	Percentage Increase (Decrease)		-2.92%	0.00%	-2.77%
32					
33	1) The Fixed Charge and the O&M Charge will be apportioned among the CARMs				
34	based upon each CARM's monthly Demand Ratio Share.				

EXHIBIT GEP-7

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

ENVIRONMENTAL COMPLIANCE ADJUSTMENT RIDER (ECAR)

TARIFF

Effective Date: November 1, 2013

PURPOSE

The purpose of the Environmental Compliance Adjustment Rider ("ECAR") is to provide a revenue recovery mechanism that will create a fund to be used for the purpose of meeting environmental compliance obligations mandated or expected to be mandated by federal, state, or local laws or regulations. The ECAR is the tariff collection mechanism for the overall Environmental Compliance Strategy ("ECS") developed by Arizona Electric Power Cooperative, Inc. ("AEPCO" or "Company") and its Members.

APPLICABILITY

Applicable to all Class A Member Distribution Cooperatives of AEPCO.

TERMS AND CONDITIONS

1. The initial rate of the tariff shall be set at zero. AEPCO will calculate a specific dollar amount necessary to fund the ECS plan and allocate a portion of that amount to each Class A Member on the basis of the Allocated Capacity Percentage ("ACP") of each Member. AEPCO will also establish a necessary term of collection for the fund. Once the dollar amount for the fund and the term of collection have been established, AEPCO will file the ECS plan and a revised tariff with the Arizona Corporation Commission ("ACC" or "Commission").* The initial ECS plan and initial revised ECAR tariff will be subject to a sixty (60) day ACC Staff review period. The revised tariff shall become effective at the end of the sixty (60) day period unless the Commission elects to suspend the revised tariff, in which case it shall become effective upon Commission approval or by operation of law. Once the revised tariff is effective, each Member will be assessed a monthly charge on its bill in addition to other rates and charges approved by the Commission. Exhibit A sets forth the monthly Member charges and anticipated term of collection.

2. The level of funding and ECAR rates may be adjusted (up or down) depending on the actual environmental compliance funding needs of the Company as outlined in the ECS plan. Any changes to the ECS and ECAR tariff after the initial ECS plan is filed will be subject to a thirty (30) day ACC Staff review period.* The revised tariff shall become effective at the end of the thirty (30) day period unless the Commission elects to suspend the revised tariff, in which case it shall become effective upon Commission approval or by operation of law.

3. Upon completion or termination of the ECS plan, AEPCO will file a revised tariff returning the rates to zero. Any funds collected under the ECAR tariff not needed to meet the Company's objective(s) for the ECS will be refunded to members over a twelve-month period in the same pro-rata shares established for collections.

Details of the operation of the ECAR and ACC compliance requirements are as set forth in the Company's Plan of Administration.

*In order for the ECAR to be revised, AEPCO must obtain Board approval and the unanimous consent of its Class A Members.

EXHIBIT A

The Monthly Charge shall be as follows for each of the Company's Class A members:

	November 1, 2013*
Collective All-Requirements Members:	
Anza Electric Cooperative, Inc.	$0.00/mo.
Duncan Valley Electric Cooperative, Inc.	$0.00/mo.
Graham County Electric Cooperative, Inc.	$0.00/mo.
Partial Requirements Members:	
Mohave Electric Power Cooperative, Inc.	$0.00/mo.
Sulphur Springs Valley Electric Power Cooperative, Inc.	$0.00/mo.
Trico Electric Cooperative, Inc.	$0.00/mo.

*The stated Monthly Rate applies to service provided on and after this date for a term of **[insert]**.

EXHIBIT GEP-8

Exhibit GEP-8

Arizona Electric Power Cooperative, Inc.

Environmental Compliance Adjustment Rider

Plan of Administration

ECAR – Plan of Administration

General Description:

The purpose of the Environmental Compliance Adjustment Rider ("ECAR") Surcharge is to establish a fund to be used for the purpose of meeting, in whole or in part, the cost of environmental compliance obligations imposed on or applicable to Arizona Electric Power Cooperative, Inc. ("AEPCO") that are mandated or expected to be mandated by federal, state or local laws or regulations or judicial or regulatory agency interpretations of such laws or regulations ("Environmental Regulations").

Key Definitions:

1. ECAR Surcharge – A rider tariff established by Arizona Corporation Commission ("ACC" or "Commission") Decision No. _____, which authorizes AEPCO to: recover or mitigate Environmental Regulations operations' costs; recover stranded asset costs as a result of asset impairment caused by Environmental Regulations; or fund, in whole or in part, capital additions required by Environmental Regulations.

2. Environmental Compliance Strategy ("ECS") – A formal plan developed by AEPCO to meet Environmental Regulations. The ECS shall include, at a minimum, a scope of work, anticipated timelines and cost estimates.

3. Qualified ECS Costs – Costs identified in the ECS plan and established by the Commission as appropriate for recovery through the ECAR Surcharge pursuant to ACC review of the ECS plan. Environmental fines or penalties do not qualify for cost recovery through the ECAR Surcharge nor do costs that have been included as part of AEPCO's authorized cost of service for recovery through established rate tariffs.

Accounting:

Funds collected from the ECAR Surcharge will be separately identified by AEPCO and recorded as a regulatory liability. Accounting for these funds shall be done on a contributing Member Distribution Cooperative basis. Use of these funds to meet Qualified ECS Costs will reduce that regulatory liability on a dollar-for-dollar basis. Funds used to support operations' expense or recover stranded asset costs will be recorded as energy sales revenues. Funds used for qualified environmental capital additions will be recorded as contributions in aid of construction.

Investment Administration:

AEPCO will deposit all funds collected through the ECAR Surcharge in a separate interest bearing investment account ("ECAR Surcharge Account") and may only draw monies from the account to fund Qualified ECS Costs. Interest earned on the investment of these funds shall be retained in the account. Upon completion or termination of the ECS plan, all remaining funds in the ECAR Surcharge Account, including interest, will be refunded to Members over a twelve-month period in the same pro-rata shares established for collections.

Compliance Reports:

On September 1 for the January through June period and March 1 for the July to December period of each year, AEPCO will file semi-annual reports concerning the ECAR Surcharge with the Commission, with a copy to its Members, containing the following information for the reporting period:

1. The beginning balance of the ECAR Surcharge Account.
2. The total amount collected by the ECAR Surcharge.
3. The total amount of interest earned by the ECAR Surcharge Account.
4. The total withdrawals for Qualified ECS Costs.
5. The ending balance of the ECAR Surcharge Account.

AEPCO will also file the following supporting information with the semi-annual report:

1. A listing of the dates and amounts of withdrawals.
2. A description of each Qualified ECS Cost paid for during the period and the accounting for each cost.

Each report will be certified by AEPCO's Chief Executive Officer or Chief Financial Officer that all information provided in the filing is true and accurate to the best of his or her information and belief.

ECS and ECAR Surcharge Modifications:

Pursuant to Commission order, the initial ECAR rate shall be set at $0.00. Thereafter, in response to an Environmental Regulation, AEPCO shall file its initial ECS plan and a revised tariff with Docket Control. The initial ECS plan and initial revised ECAR tariff shall be reviewed by ACC Staff and take effect sixty (60) days after filing, unless the Commission enters an order suspending the filing, in which case it shall become effective upon Commission approval or by operation of law.

Any changes to the ECS and ECAR tariff after the initial ECS plan is filed will be subject to a thirty (30) day ACC Staff review period and shall become effective at the end of the thirty (30) day period unless the Commission elects to suspend the revised tariff, in which case it shall become effective upon Commission approval or by operation of law.

Upon the completion or termination of the ECS plan, AEPCO will file a revised tariff returning the rates to zero. The rates shall remain at zero until AEPCO deems it necessary to utilize the ECAR tariff again in response to an Environmental Regulation, in which case it will prepare and file an initial ECS plan and initial revised tariff for Commission consideration.

AEPCO Board Approval and Member Consent:

Prior to filing an initial ECS plan and revised ECAR tariff or seeking a subsequent modification to either the ECS or ECAR, AEPCO will obtain authorization from its Board. AEPCO shall also notify its Member Distribution Cooperatives sixty (60) days in advance of a proposed filing with the Commission in order to confirm the unanimous consent of its Members. Absent receipt of timely written objections, Member consent shall be deemed obtained and AEPCO may proceed with the filing.

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

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

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-12-0305

Rebuttal Testimony of Richard P. Kurtz

on Behalf of

Arizona Electric Power Cooperative, Inc.

General Rates Application

June 13, 2013

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INTRODUCTION

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

A. My name is Richard (Dick) Kurtz. 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. as its Vice President of Power Services and Planning. In that role, I am responsible for preparing, negotiating and managing power- and transmission-related wholesale contracts with the Class A Members and other utilities on behalf of the Arizona Electric Power Cooperative, Inc. ("AEPCO") and the Southwest Transmission Cooperative, Inc. ("SWTC"). In my Planning Role, I am responsible for directing and administering the resource and transmission planning functions of AEPCO and SWTC.

Q. Please briefly summarize your educational background.

A. I graduated in 1971 from the University of New Mexico ("UNM") with a Bachelor of Science in Electrical Engineering. In 1971, I completed a course in Power Systems Analysis presented by Ohio State University; in 1972, I attended Westinghouse Relay School; and in 1975, I earned my Professional Engineering certificate in New Mexico. In 1992, I completed a graduate-level program on accounting and finance aspects of business administration that was offered by my then current employer in conjunction with UNM's Robert O. Anderson School of Management. Over the course of my employment, I have attended and received training in a variety of aspects of power and transmission system planning, project management, business administration and contract preparation and administration.

Q. Please briefly summarize your utilities-related professional experience.

A. In 1971, I was hired by Cincinnati Gas & Electric Company as an electric system planning engineer. In early 1974, I began my employment with Public Service Company of New Mexico ("PNM") as a senior transmission planning engineer. In 1981, I transitioned to the PNM Power Contracts area, where I was largely responsible for preparing and negotiating transmission participation and wheeling contracts with utilities interconnected with PNM and for preparing the associated filings with the Federal Energy Regulatory Commission.

In early 1995, I began my employment with AEPCO in the position of Director of Power Services. I participated in the team that formed the wholesale power and transmission contracts between AEPCO and SWTC and among AEPCO, SWTC and the Class A Members, which resulted from AEPCO's restructuring that became effective in 2001. In late 2005, I became AEPCO's Vice President of Power Services.

In early 2006, AEPCO joined with 38 other public power entities to form the Southwest Public Power Resources ("SPPR") Group, an association for joint planning of future resources. I act as administrator for the SPPR Group.

APACHE STATION – AEPCO'S REBUTTAL POSITION

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to the "Final Report – Review of AEPCO – Engineering Analysis and Power Plant Operations" ("Final Report"). It is Exhibit RAM-2 to the direct testimony of Richard Mazzini of The Liberty Consulting Group. There are several Final Report observations and conclusions we agree with. For example, at page 1, Mr. Mazzini summarizes the following Liberty findings: (1) Apache Station's technical performance, its people and its facilities are sound; (2) AEPCO's management team is knowledgeable, engaged, open and supportive of Liberty's evaluation; (3) our organization has the expertise and the tools commensurate with the needs and challenges of the station; (4) Apache Station's plant operations are appropriate; (5) our maintenance practices and spending are efficient and consistent with good utility practices; and (6) Apache Station is well-maintained.

However, AEPCO does disagree with portions of the Final Report. That is where the focus of my testimony lies. Specifically, I address Mr. Mazzini's remarks regarding (1) AEPCO's October 2012 Report re the Future Role of Apache Station; (2) the need for AEPCO to conduct a further study of Units ST1, ST2 and ST3; (3) his conclusion that ST1 is not used and useful and that a 2010 investment in ST1 was not economically justified; and (4) his characterization that AEPCO's coal Units ST2 and ST3 are caught in a downward spiral which causes him to question their usefulness through 2035 – the current term of the AEPCO wholesale power contracts with its Class A Members. In connection with my discussion of the future life and use of Units ST2 and ST3, I will also address concerns raised by Mr. Mazzini, as well as other Liberty witnesses, regarding the EPA's recent ruling on regional haze requirements for Apache Station.

Q. In what form is your testimony provided?

A. My testimony is provided through the attached report entitled "AEPCO's Response to the Final Report of Richard Mazzini." That report is organized as follows:

Section 1: Introduction

Section 2: Apache Station ST2 and ST3 Output – 2000 to Date and Its Future

Section 3: Assessment of ST1 2010 Repairs, Its Operational Usefulness and Life

Section 4: Past and Ongoing Apache Station Strategic Planning

Q. Please summarize the conclusions of your report with respect to Apache Station output.

A. Our knowledge of Apache Station's history, coupled with our review of the data, does not support Mr. Mazzini's conclusion that Apache Station – particularly its coal units ST2 and ST3 – are caught in a downward spiral similar to challenges faced by coal units nationwide. The decline in output referenced by Mr. Mazzini (via a comparison of output in his selected years of 2000, 2009 and 2012) was not a constant "spiral" over the 12-year period. Instead, it was concentrated in two periods at the beginning and the end of this 2000-2012 timeframe, with steady output in-between. Further, those two periods of decline were produced by local and regional market forces, contract expirations and coal supply and rail transport conditions unique to AEPCO, as well as the circumstances of the specific years at issue. The decline in those two periods was not attributable to any factors indigenous to the units. Apache Units ST2 and ST3 are now operating and are expected to continue to operate over the next several years, at levels exceeding those experienced in 2009 and at levels substantially greater than in 2011 and 2012.

Q. Please summarize your report with respect to the ST1 2010 repairs and operational usefulness.

A. I focus on two conclusions in Mr. Mazzini's Final Report – the first challenging repairs to ST1 conducted in 2010 and his second stating that the unit is no longer used and useful. As to the 2010 investment, AEPCO took the appropriate action, both contractually and practically, to repair ST1 (which is normally operated in combined cycle mode known as "CC1"). In fact, Liberty's Public Report in AEPCO's last rate case evaluated AEPCO's ST1 repair decision and concluded that "**Experience and recent management study confirm the continuing usefulness of CC1 and the gas turbine units.**" (Bolding in original.) A large part of AEPCO's 2010 decision to conduct the repairs was based on ST1's value as capacity. That value continues and supports the unit's useful life through 2020. Additionally, ST1 provides backup to coal unit operations and remains available as intermediate summer generation, if needed. For these reasons, AEPCO's Unit ST1 is used and useful. Its current depreciation rates through 2020 are correct and should be approved.

Q. Please summarize your report with respect to AEPCO's past and ongoing strategic planning regarding Apache Station.

A. This section of my report responds to Mr. Mazzini's recommendation that AEPCO conduct a comprehensive study of Apache Station. As an initial matter, AEPCO believes that Mr. Mazzini's recommendation is based on an incorrect assessment of Apache Units ST1, ST2 and ST3 – specifically his belief that ST2 and ST3 are in a downward spiral and his conclusion that ST1 is no longer used and useful. As explained in other sections of my report and summarized above, the data does not support Mr. Mazzini's concerns about these units.

Further, to the extent that his further study recommendation is a reaction to the EPA's 2012 FIP regarding regional haze, my report explains that AEPCO has been analyzing related environmental regulations for the past six years and, thanks to that prior planning, we were able to promptly respond with an alternative proposal that is currently being reviewed by the EPA. AEPCO's alternative, if approved, will secure the future of ST2 and ST3 at <u>substantially less cost</u> than the requirements of the current FIP. The proposal consists of switching ST2 to natural gas and installing a SNCR retrofit of ST3. It will require only about $30 million in contrast to the estimated $200 million cost of the EPA's original FIP. Also, in the course of analyzing the FIP, AEPCO assembled a Strategic Resource Planning Group, which participated in the development of our FIP proposal. The Group is using that experience to continue to evaluate how AEPCO can help Class A Members best address their future load growth. Based on these past and ongoing strategic planning efforts, we do not believe it is necessary to prepare yet another formal study of Apache Station as Mr. Mazzini suggests.

Q. Does your report also address the useful lives of ST2 and ST3?

A. Yes. As indicated above, AEPCO is confident in the ability of ST2 and ST3 to continue to operate and meet our Members' needs for power and energy in the future. In fact, AEPCO's FIP proposal is designed to maintain the viability of these units well into the 2030s, which is consistent with and supportive of the Black & Veatch conclusion that "ST2 and ST3 can continue operation to 2035." Accordingly, the useful lives of these units to the year 2035 – as required by the Company's wholesale power contracts with its Class A Members – are adequately supported, as are their associated depreciation rates. AEPCO requests Commission approval of the Black & Veatch revised depreciation rates stated in Exhibit PS-2 to Mr. Scott's direct testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

AEPCO'S RESPONSE TO
THE FINAL REPORT OF RICHARD MAZZINI

June 13, 2013

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SECTION 1
INTRODUCTION

On May 1, 2013, Richard Mazzini of The Liberty Consulting Group filed testimony on behalf of the Staff of the Utilities Division of the Arizona Corporation Commission in AEPCO's rate case, Docket No. E-01773A-12-0305. Attached to his testimony as Exhibit RAM-2 was his report entitled the "Final Report – Review of AEPCO – Engineering Analysis and Power Plant Operations" ("Final Report"). The stated purpose of the Final Report was to present the results of Liberty's evaluation of AEPCO's Apache Station, including station performance, operations, maintenance, and capital improvements.

AEPCO has reviewed the Final Report. The purpose of my report is to provide AEPCO's response to certain statements made and conclusions reached by Mr. Mazzini in the Final Report. To the extent that some of Mr. Mazzini's remarks are discussed and incorporated into the direct testimonies of other Liberty witnesses, including those of Dennis Kalbarcyzk and John Antonuk, this report is intended to address those other witnesses' statements and conclusions as well.

My report is divided into four sections:

Section 1: Introduction
Section 2: Apache Station ST2 and ST3 Output – 2000 to Date and its Future
Section 3: Assessment of ST1 2010 Repairs, its Operational Usefulness and Life
Section 4: Past and Ongoing Apache Station Strategic Planning

Each of these sections addresses specific issues raised in the Final Report. Collectively, they support AEPCO's response to Mr. Mazzini's single recommendation at page 3 of the Final Report – that a comprehensive study of the future of Apache Station should be completed. AEPCO disagrees with this recommendation for a number of reasons.

First, Mr. Mazzini's recommendation appears to be based on his belief that ST2 and ST3 are in a downward spiral and ST1 is no longer used and useful. My report demonstrates the inaccuracy of those concerns. The recommendation also appears to grow out of concerns regarding environmental regulations, specifically the EPA's recent Federal Implementation Plan ("FIP"). As I explain, the EPA very recently granted AEPCO's Supplemental Petition for Administrative Reconsideration, which proposes an alternative to ensure the viability of Apache Station well into the future.

Moreover, the substantive and procedural elements of the study recommended by Mr. Mazzini are already in place. For example, AEPCO's Strategic Resource Planning Group and Technical Team continue to evaluate Apache Station (including the useful lives of its units) based on comprehensive operating scenarios, economics, physical operating conditions and the future resource needs of our Members. Additionally, AEPCO and its Members continue to use the expertise of outside consultants such as C.H. Guernsey & Co., GDS Associates and Burns & McDonnell to ensure the reliability of our planning methods, assumptions and conclusions. Finally, consistent with AEPCO's historic practice, we continue to include our Members in the ongoing analysis of Apache Station, including any impact on rates.

In summary, AEPCO does not agree with the fundamental premises underlying the Final Report's recommendation, namely that (1) the future of Apache Station is in question and (2) AEPCO has been less than diligent in its planning efforts. Because the units continue to be used and useful to our Members and we have demonstrated – with solid results – our continuing commitment to planning for Apache's future, yet another planning requirement is unnecessary and duplicative of our ongoing efforts.

SECTION 2

APACHE STATION ST2 AND ST3 OUTPUT – 2000 TO DATE AND ITS FUTURE USES

At page 4, Section C – the "Station Performance" section of the Final Report – Mr. Mazzini provides a table summarizing the output of Apache Station in years 2000, 2009 and 2012. The data aggregates output for Apache's coal-fired Units ST2 and ST3 and the gas-fired units (i.e., ST1 and GTs 1-4) to comprise Apache Total Station output. Using the comparative annual net GWh output values (the accuracy of which AEPCO does not dispute) for the three selected years of that 12-year period, Mr Mazzini points to a 39% decline in Total Station Net Output from a year 2000 high of 3,459 GWh to 2,099 GWh in 2009 and a further decline through 2012 of 492 GWh. Mr. Mazzini's stated concern is that these output declines – particularly those of ST2 and ST3 – are the result of challenges faced generally by coal units "across North America," are eroding the assets' used and usefulness and are potentially affecting their useful lives. In his summary, Mr. Mazzini characterizes Apache Station as being in a downward spiral.[1]

In this Section, I address the reasons for (1) the decline in Apache Station output in the period from 2000 through 2009, which I show occurred in two separate and distinct drops, not a "spiral"; (2) the decline in the use of ST2 and ST3 after 2009, which occurred in 2011 and 2012; and (3) the increases in ST2 and ST3 production in 2013 and as expected in future years.

Section 4 of this report addresses several related topics: (1) Mr. Mazzini's concerns about the future role of ST2 and ST3 given the EPA FIP; (2) AEPCO's progress in reaching agreement with the EPA on a much less costly solution; and (3) our analysis of the units' usefulness through 2035. In Section 3, I address Mr. Mazzini's comments concerning Unit ST1.

As explained in greater detail in this Section 2, AEPCO disagrees with – and the data and analysis do not support – Mr. Mazzini's characterization that Apache Station, particularly its coal units ST2 and ST3, are caught in a downward spiral of usefulness similar to challenges generally facing coal units nationwide. Instead, over the period selected by Mr. Mazzini, at two points Apache output was affected by various local or regional market factors, contract expirations and coal supply and rail transport conditions unique to AEPCO. None of these factors support (and in fact they refute) conclusions of a downward spiral or "troubling forces at work"[2] for Apache Station.

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[1] Liberty Report, p. 2.
[2] Liberty Report, p. 4.

DECLINE IN OUTPUT OF APACHE STATION FROM 2000 THROUGH 2009

The Final Report implies that from 2000 to 2009, Apache Station suffered from a long-term, erosive condition producing a continuous decline in output for nine straight years. Instead, my review and analysis confirm that the decline in Total Station output 2000-2009 was not a steady, gradual decline. The data instead shows that AEPCO experienced two widely separate periods of output reduction caused by distinct external events while output remained steady during the rest of the period.

The first half of Apache's usage decline occurred in 2002-2003. It was caused by the end of the California competitive market experience and the expiration of a 100 MW wholesale sales contract, both of which occurred in mid-2002, and which affected AEPCO's production from both Apache gas-fired resources and its coal-fired units ("Stage 1"). The second half of the decline – which occurred six years later in 2009 – affected production primarily from ST2 and ST3. The 2009 drop ("Stage 2") was caused by a wholly different combination of events than the Stage 1 decline: the economic downturn that started in 2008 coupled with increased delivered coal costs and declining market prices. Significantly – contrary to Mr. Mazzini's implication of a steady nine-year spiral – Apache Station's output between 2003 and 2008 remained relatively constant.

In Stage 1, by the end of 2002, total Apache Station output had declined by about 682 GWh compared to the year 2000 (*see* Exhibit RPK 2-1). The coal units' share of that decline was about 420 GWh and the balance of the drop came from Apache Other Resources' (i.e., the gas units) reduced output. This initial drop in Apache Station total output is, in part, attributable to the end of the California market's very high prices experienced in the year 2000 – the year Mr. Mazzini selected as the starting point for his decreased output analysis. AEPCO participated in that market with economy sales at levels never before or after experienced by the Cooperative. The other significant factor in the 2002-2003 Apache Station output compared to 2000 was the expiration of a 100 MW sales contract with Phelps Dodge ("PD") for its Morenci Mine in mid-2002 (potentially 876 GWh per year). The PD contract expiration primarily dropped production from AEPCO's coal-fired ST2 and ST3, while the California market element principally affected output from the Gas-Fired Other Resources – significantly GT2 and GT3. These gas-fired resources normally are the last resources AEPCO dispatches due to their relatively high heat rates. But, they were unusually saleable in 2000 through the first half of 2002 because of very high California market prices.

After Stage 1's decline, Apache Station's annual output remained fairly steady (*see* Exhibit RPK 2-1). In 2008, total station output was essentially the same as in 2003, at about 3,100 GWh.

Stage 2 of the usage decline occurred in 2009 when AEPCO experienced a drop of 753 GWh in the output of coal-fired units ST2 and ST3 (*see* Exhibit RPK 2-1). A significant portion of this decline (433 GWh) was attributable directly to the reduced take of Salt River Project ("SRP") in 2009 from AEPCO's long term 100 MW power sale agreement with SRP. The balance of the drop (320 GWh) related to the reduced take by AEPCO and its Class A Members.

The fact that both SRP and AEPCO's Members reduced their take in 2009 points first to the economic downturn that started in 2008. At that time, several of our Class A Members, as well as SRP, were experiencing no load growth in light of the economic recession.

However, another more significant factor in the reduction in take was attributable to increased energy costs, which in turn were caused by AEPCO's high rail costs. As discussed in another Liberty report attached to the direct testimony of John Antonuk, higher Apache inventoried coal costs began in 2009 as the result of the new rail transportation rates imposed by the Union Pacific Railroad. Those high rail rates made access by AEPCO and purchases from better priced, but more remote, coal mines non-competitive. Therefore, AEPCO was forced to contract with a nearer coal mine. The mine demanded a significant increase in coal prices because it knew it faced no other supply competition given the high rail rates. The impact of this coal/rail cost tandem was dramatic. AEPCO's inventoried cost of coal leapt by about 50% from an average of $1.91 per MMBtu in 2008 to an average of $2.85 per MMBtu in 2009 (*see* Exhibit RPK 2-2). That corresponds to an increase in average AEPCO energy costs from roughly $21 per MWh to $33 per MWh.

Compounding that coal/rail cost impact was the fact that, at the same time as this increase occurred in AEPCO's energy costs, market power prices generally were decreasing. Exhibit RPK 2-3 shows historic Palo Verde ("PV") "7 by 24" prices based on a blend of Peak and Off-peak prices for each of the years 2008 through 2012. In 2008, the PV price was over $89 per MWh at its summer high, while one year later the summer high price was only $32 per MWh. A similar disparity existed between the average PV prices of 2008 at $63 per MWh and those of 2009 at only $30 per MWh.

The drop in 2009 market prices compared to AEPCO's increased coal costs incented SRP under its 100 MW sales contract to choose market power instead of energy from ST2 and ST3. AEPCO's Members made the same market-based decision (*see* Exhibit RPK 2-4 (2009)). Notably, 2009 was the first year since the inception of the PRM option that the PRMs purchased energy to displace their interest in coal-fired energy to any significant degree. As discussed below, AEPCO's high coal costs continued to impact ST2 and ST3 output until the Cooperative succeeded in challenging its rail rates before the Surface Transportation Board ("STB") in late 2011.

The conclusion to be drawn from this 2000-2009 usage pattern is not Liberty's "indications that more troubling forces [were] at work." Instead, approximately half of the usage drop occurred early in the period Mr. Mazzini selected, primarily as the result of the end of extraordinary California market prices coupled with the PD contract expiration. Meanwhile, the other half was attributable to a combination of AEPCO costs and economic factors in 2009, significantly the increase in the delivered cost of coal coupled with a parallel decline in market prices.

DECLINE IN OUTPUT OF ST2 AND ST3 FROM 2009 THROUGH 2012

Mr. Mazzini's chart on page 4 of the Final Report shows a decline of output from ST2 and ST3 of more than 400 GWh between 2009 and 2012. However, when considered year-by-year, it is clear that the decline was not a trend but the result of several isolated factors that no longer exist.

As for 2010, the production from ST2 and ST3 actually increased from that of 2009 by some 146 GWh. 68 GWh of that increase was due to SRP increasing its take under the 100 MW sale contract to 490 GWh (*see* Exhibit RPK 2-1), with the balance of the modest increase attributable to the Class A Members, even as their loads continued to decline (*compare* Exhibit RPK 2-4 (2009) with Exhibit RPK 2-4 (2010)). This slight production increase was likely caused by an increase in market prices (from an average of $30 MWh in 2009 to an average of $34 per MWh in 2010) while AEPCO's coal costs remained high, but relatively stable.

Turning to 2011, the SRP sales contract expired at the end of 2010. The 490 GWh loss in ST2 and ST3 production caused by SRP's contract expiration was offset by gains in Member use of the units such that the output decreased from 2010 to 2011 by only 208 GWh (*see* Exhibit RPK 2-1). The increase in Member use from 2010 to 2011 is attributable to the return of some 90 GWh of Class A Member load as well as reduced market purchases (*compare* Exhibit RPK 2-4 (2010) with Exhibit RPK 2-4 (2011)). The decrease in market purchases by the Members is likely the result of the January 1, 2011 implementation of the new energy rates from AEPCO's prior rate case, which provided separate Base and Other Resources energy prices so as to more clearly reflect costs of production.

Production from ST2 and ST3 declined in 2012 by 387 GWh. In 2012, natural gas and market prices dropped fairly steeply from 2011 levels to average less than $26 per MWh (*see* Exhibit RPK 2-3). This market price decrease caused both AEPCO and its Members to increase market purchases in lieu of taking energy from ST2 and ST3 (*see* Exhibit RPK 2-4 (2012), which costs showed only a modest decline (to less than $34 per MWh), reflecting just the beginning of AEPCO's victory over the railroads before the STB in late 2011.

In conclusion, the decline in ST2 and ST3 production from 2009 through 2012 also does not support Mr. Mazzini's "troubling forces" assertion. Rather, the data shows that the decline was only a two-year event in 2011 and 2012 and was caused by isolated, non-recurring factors: (1) high coal prices (which have now been corrected by the STB ruling); (2) the scheduled end of SRP's 100 MW, 20-year sales contract; and (3) a dramatic decrease in market prices in 2012.

USE OF ST2 AND ST3 FOR 2013 AND INTO THE FUTURE

Perhaps the most compelling evidence disproving Mr. Mazzini's downward spiral theory is the dramatic turnaround in 2013 of production from ST2 and ST3 combined with expectations concerning production from these units into the near future.

As mentioned, AEPCO's successful STB rail rate case decision in late 2011 began to produce modestly lower inventoried coal costs in 2012 and positioned AEPCO for even lower coal costs in 2013 (averaging $31 per MWh to date). The cost decline is forecast to continue through the remainder of this year. Exhibit RPK 2-5 contains the results of AEPCO's recent request to ACES to re-assess 2013 coal burn expectations based on current gas and market prices. Given that assessment, AEPCO now expects to burn more than 1.3 million tons of coal this year at an effective average cost of approximately $29 per MWh. That price is (1) substantially less than projected average market price of $34+ per MWh for 2013 and (2) competitive with off-peak market prices through at least September. The result is an expected marked increase in coal generation output (*compare* Exhibit RPK 2-5 (2013 coal tons) with Exhibit RPK 2-2 (prior years' actual coal tons)). In fact, AEPCO is now experiencing higher levels of coal-fired generation than it has seen for five years.

Finally, we expect AEPCO's declining inventoried coal costs coupled with increasing market prices as currently forecast (*see* Exhibit RPK 2-6) will enable the energy production from ST2 and ST3 to remain steady or increase from the 2013 experience over the next several years.

SECTION 3
ASSESSMENT OF ST1 2010 REPAIRS, ITS OPERATIONAL USEFULNESS AND LIFE

At pages 7-8, Section C.2 of the Final Report, Mr. Mazzini discusses "Steam 1 and Gas Turbine 1," which are also known as "CC1." Mr. Mazzini provides a graph illustrating that the operation of these two units in combined cycle mode declined from 60 percent in 2000 to "mid-single digits" by 2004. Further, he notes that CC1 has had "virtually no output" and "suddenly stop[ped] operating" since AEPCO invested in repairs to ST1 in 2010. Mr. Mazzini maintains that these circumstances make it "difficult to justify the costs associated with this unit." In response to AEPCO's position that ST1 has real and tangible value as capacity, Mr. Mazzini concludes that the unit is no longer used and useful based on its lack of operation in 2011 and 2012.

In this section, I discuss the practical and contractual justifications that AEPCO provided its Board of Directors and each Class A Member to explain the 2010 capital investment (which Liberty supported at the time). I also discuss the reasons that AEPCO did not operate ST1 in 2011 and 2012, which seems to be Mr. Mazzini's primary concern. As explained below, ST1 continues to have value as capacity to AEPCO and its Class A Members. It will continue to operate primarily as capacity in support of cost efficient economy energy purchases. It also will continue its other important role as support for coal unit maintenance and longer term forced outages, as it did historically from 2004 through 2009. Finally, I address the potential costs of replacing CC1's capacity, which also supports its ongoing usefulness.

ST1 is a 72 MW net gas-fired steam unit. It is normally operated in combined cycle mode with GT1 (a 10 MW combustion turbine) as CC1 (82 MW total). Except for CC1's extensive use during the period of high California market prices in 2000-2002, as discussed in Section 2 of this report, AEPCO and its PRMs historically have used CC1 as an intermediate resource. In winter, the off-peak season's low market prices favor market purchases against CC1's capacity. However, CC1's energy cost is normally most comparable to the market in summer peak times, when gas prices are lower and market prices higher. Thus, for many years CC1 was operated in summer to cover peak load and as insurance against any summertime forced outages of the coal-fired units. To a more limited extent, historically CC1 was also run during spring and fall coal maintenance outages. When run, its daily operation would typically follow load in the peak hours up to its 82 MW of capacity and at a minimum level overnight. Exhibit RPK 2-1 confirms this historical use in that it shows the combined annual output of ST1 and GT1 ranged from 43 GWh at its low to almost 70 GWh at its high during the 2004-2009 period.

Another important factor in ST1's resource role is that the wholesale power contracts between AEPCO and each of its Class A Members require CC1 be maintained as a viable resource through 2020. The CC1 capacity requirement is in Appendix B to Exhibit A-5 to both the PRM and ARM Rate Schedules A, which were approved by the Commission in AEPCO's last rate case.[3] In addition, Section 4.4 of Schedule B of the PRM contracts requires AEPCO to have CC1 available for production for the following purposes:

> "[A]vailable in the summer period (May through October) for daily operation around the clock as may be required to preserve load serving capability and backup to forced outage of coal-fired Existing Resources. Winter period use is permitted during coal maintenance outage periods and during winter peak months of December and January, but every effort should be made to utilize market purchases prior to committing the unit in winter months."

Given CC1's historical use together with these contractual obligations, AEPCO evaluated whether to undertake repairs to ST1 in the spring of 2010 after discovering abnormally high tube erosion issues in the unit in late 2009. AEPCO produced a formal report on the subject, which is attached as Exhibit RPK 3-1. Based on that report and AEPCO staff's recommendation, the Cooperative's Board of Directors approved the repair for an estimated cost of \$3.9 million.[4] Attached as Exhibit RPK 3-2 are the April 2010 Staff Summary and Board Resolution. These materials were provided to Liberty in AEPCO's last rate case, resulting in Liberty's endorsement of AEPCO's decision to repair ST1. Relevant portions of Liberty's July 30, 2010 Public Report are attached as Exhibit RPK 3-3 (*see* page 72, "**Experience and recent management study confirm the continuing usefulness of CC1 and the gas turbine units**" (bolding in original)).

Mr. Mazzini is correct that "[f]ollowing the 2010 overhaul, [CC1] has had virtually no output."[5] But, the conclusion to be drawn from that isolated fact is <u>not</u> that ST1 has lost its usefulness.

Because the repairs to ST1 were conducted in the summer of 2010, its next usual operation would not have occurred until the summer of 2011. In 2011, based on available market data,

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[3] Decision No. 72055, 2nd and 3rd Ordering Paragraphs, pp. 16-17.
[4] The actual cost of the repair was approximately \$500,000 under budget.
[5] Liberty Report, p. 7.

AEPCO proposed to its Class A Members that the market be relied upon that summer because of the potential savings to be realized from market purchases compared to the higher costs of running CC1. They agreed and approved the proposal. Since 2011, prior to each summer period, AEPCO has issued a similar communication to the Class A Member CEOs presenting a cost-benefit analysis of keeping ST1 off-line rather than running it and seeking their concurrence in the proposed approach. Each year, the Class A Member CEOs have agreed to that proposal. Exhibit RPK 3-4 is the 2013 correspondence to the CEOs in that regard with the summary of CC1 production costs versus the forward market purchase prices.

Thus, even when not being "used," CC1 and the GTs of Apache Station serve an important and useful role as firm capacity against which the PRMs and AEPCO, on behalf of the ARMs, can purchase energy. Exhibit RPK 3-5 compares the monthly Allocated Capacity of the Class A Members in aggregate to the aggregated monthly peak demand of their total loads for the years 2011 and 2012 – the period following expiration of the SRP 100 MW sale contract (discussed in Section 2 of this report). This Exhibit demonstrates that the capacity of AEPCO Resources, including CC1, covered the capacity needs in aggregate of all the Class A Members except for less than 25 MW in June, July and August of 2011 and 31 MW in August of 2012. During these years, AEPCO's PRMs saved money by purchasing more economical market energy against their Apache Resource capacities. In the event their AEPCO Resource capacities were deficient, it is my understanding that the PRMs purchased monthly or weekly energy blocks during peak or super-peak hours. Between AEPCO (on behalf of its ARMs) and the PRMs, those purchases totaled 585 GWh in 2011 and almost 946 GWh in 2012 (*see* Exhibit RPK 2-4 (2011) and Exhibit RPK 2-4 (2012)). Further, when AEPCO or its PRMs purchase on the market against these Resources, those purchases do not guarantee load serving entities – like the Class A Members – that the energy may not be curtailed and need to be replaced. Thus, the capacity provided by CC1 serves as resources that minimize these risks, which could otherwise require the Members to curtail load.

In addition, under the wholesale power contracts, AEPCO must ensure from a planning and operations perspective that (1) the ARMs have capacity sufficient to meet their collective peak demand and (2) the PRMs can rely on their Allocated Capacities. Without CC1 in AEPCO's resources, AEPCO would have to replace it with something else at least for the summer season. As a point of cost comparison, AEPCO currently has in place the Southpoint and Griffith Purchased Power Agreements ("PPAs") – summer season PPAs that were entered into in 2004. These PPAs provide capacity that is able to be dispatched on a day-ahead basis, comparable to that of CC1. The monthly demand rate for the Griffith PPA (the lesser demand rate of the two) is $6.30 per kW-month, which for six months would be $37.80 per kW. In contrast, the monthly fixed cost of CC1 is $2.36 per kW-month, for a much lower yearly capacity cost of $28.30 per kW. Thus, (1) CC1 has a clear capacity cost advantage over a summer season PPA and (2) CC1 is available year round, which obviously further increases its value.

Finally, CC1 capacity represents an important hedge against a future time when the surplus capacity that has prevailed in the Arizona market for the past decade will become committed to serve third-party, not utility, loads. Recent sales suggest that this capacity shortfall may not be that far away (e.g., the sale of a Mesquite unit; past sales of two Gila River Generating Station units to a large investment firm; and the recent attempt by the same investment firm to purchase the Harquahala Generating Station). The resulting capacity shortage could well require a return to the operation of CC1 and the peaking units more typical of their usage prior to 2004 (*see* Exhibit RPK 2-1).

As a side note worth mentioning, one of the other reasons for the PRM practice of replacing CC1 energy with market energy has been a lack of transparency of AEPCO's true dispatch costs. As referenced in Section 2 of this report as well as the rebuttal testimony of Gary Pierson (page 6), prior to the effective date of our tariffs approved in the last rate case, AEPCO's energy rates were sending somewhat flawed price signals. We believe that the improved tariffs that went into effect in 2011 combined with the revisions to the PPFAC proposed in our present rate case (and supported by Liberty) will further aid in sending more accurate and timely purchase information to encourage a more substantive, cost-effective dispatch of CC1.

In conclusion, Mr. Mazzini is simply incorrect – CC1 and AEPCO's other gas-fired resources are and continue to be valuable, cost-effective, used and useful assets for the supply of electric energy for our Class A Members and their member-customers. Their useful lives run through 2020 and support the revised depreciation rates set forth in the Black & Veatch study.

SECTION 4
PAST AND ONGOING APACHE STATION STRATEGIC PLANNING

At page 5 of his report, Mr. Mazzini notes the Commission in the 2010 rate case decision instructed AEPCO to "conduct a study of the future role of Apache and how that role relates to member needs for future power supply." He acknowledges that AEPCO filed the study (the "Apache Study") on October 22, 2012. However, Mr. Mazzini claims that the Apache Study – which consisted of a nine-page report with three appendices and an 18-page Exhibit A examining all EPA rulemakings which could impact the station – was deficient. First, he states that the Apache Study "failed to address key fundamental questions." Second, he states that on August 22, 2012 AEPCO "submitted an Integrated Resource Plan that failed to acknowledge or even discuss the deteriorating role and questionable future of Apache."[6] Third, he finds fault with Black & Veatch's "Affirmation of Unit Life & Net Salvage Value Study" that supports the useful life of the Apache Station units through 2020 and 2035 because the study failed to "consider any economic factors that might shorten the life of the units." Mr. Mazzini correctly notes that "[m]ore recently the problems posed by the EPA have taken center stage" but mistakenly concludes that these "have served as [AEPCO's] reason for avoiding the economics discussion." Based on his belief that AEPCO has not conducted a sufficient analysis of Apache Station, Mr. Mazzini makes a single recommendation at page 3 of his report – that AEPCO conduct a comprehensive study of the future of Apache.

AEPCO disagrees with Mr. Mazzini's basic premise that Apache Station is in decline and may not be useful through 2035. Mr. Mazzini's findings regarding the continued usefulness of Units ST1, ST2 and ST3 are addressed and refuted in Sections 2 and 3 of this report. The Apache Study which we filed last year contained similar information supporting AEPCO's view that the

[6] AEPCO actually made its Integrated Resource Plan filing five months earlier, on March 30, 2012, so I don't know what filing is referenced here by Mr. Mazzini.

operations of ST2 and ST3 in 2009 were, in fact, anomalous and not a trend. As described in Section 2, the return to a more vigorous 2013 Apache output reinforces the accuracy of that conclusion. Further, and as I discussed in Section 3, the operation of ST1 in combined cycle mode clearly has a valuable future role for AEPCO and its Members as (1) capacity for market purchases, (2) backup to coal unit operations and (3) potentially as intermediate summer generation. Sections 2 and 3 support our Apache Study conclusions regarding the station's 2009 performance as well as its future role in meeting Member needs.[7]

The remaining issue appears to be whether Apache's coal-fired units can withstand the potential costs that may be incurred to comply with future EPA regulations, particularly MATS (mercury and air toxics standards) as well as possible regulations regarding coal as a boiler fuel. While AEPCO could not predict precise future EPA, Congressional or State actions on those subjects in preparing its Apache Study, each of those and other environmental issues and their potential applicability with respect to Apache were discussed in the Apache Study's 18-page Exhibit A.

In this Section 4, I summarize AEPCO's past, current and future investigation and actions addressing these environmental regulations and their potential impact on Apache Station. I present the merits of AEPCO's regional haze plan and the reasons why Apache will continue as a viable operating generation station well into the 2030's. Finally, I urge the Commission to find that our ongoing planning efforts are more than sufficient to address any concerns regarding Apache Station, such that yet another formal study would be duplicative and unnecessary.

PAST EFFORTS

AEPCO began preparing its Apache Station best achievable retrofit technology ("BART") analysis six years ago in the spring of 2007. CH2M Hill was selected as our expert consultant in

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[7] The Apache Study's focus on 2009 station performance was triggered by Liberty's July 2010 report, at page 71, where the consultants stressed that the "key question is whether 2009 conditions are anomalous or a warning of deterioration." In light of our confirmation that 2009 was an anomaly, the Apache Study also evaluated the future of ST2 and ST3 in light of known and anticipated economic factors and in comparison to other units around the country. AEPCO concluded (we believe correctly) that, while the units may operate at lower capacity levels than in some prior years, that mode of operation would not limit their future usefulness.

May of 2007. Its draft report was provided to AEPCO for review and comment in late 2007 and the final BART analysis was submitted to the Arizona Department of Environmental Quality ("ADEQ") in February 2008. AEPCO's BART analysis was adopted by the State of Arizona as part of its State Implementation Plan ("SIP") and was submitted to the EPA in February 2011.

AEPCO's BART analysis, as adopted by ADEQ, proposed low NOx burners and overfire air for the coal units, ST2 and ST3. For sulfur dioxide ("SO_2") and particulate matter ("PM"), the recommended technologies were upgrades to the existing scrubbers and hot-side electrostatic precipitators. The estimated cost, in 2007 dollars, for the proposed coal unit technologies was $4,760,000 per unit. For ST1, the proposed NOx reduction technology was low NOx burners with flue gas recirculation. Mitigation technology for SO_2 and PM was not required on ST1 due to the very low sulfur and particulate qualities of the option fuels, pipeline natural gas and low-sulfur No. 2 fuel oil. The total estimated cost for BART technology on ST1 was $2,100,000 (2007 dollars).

AEPCO became aware of the requirement for utility maximum achievable control technology ("UMACT") for mercury and other hazardous air pollutants in late 2011. In January 2012, AEPCO assembled a task force to address UMACT. The task force determined a consultant was required to examine UMACT's potential impact on Apache Station and a request-for-proposal was promptly issued on February 21, 2012. It included a scope of work to evaluate UMACT as well as future potential environmental rules, such as coal combustion residuals. The study would review current technologies, make recommendations, provide capital cost estimates and speculate as to possible implementation schedules. Burns and McDonnell was awarded this assignment on March 27, 2012. The draft of the study was delivered to AEPCO in July 2012.

At that time (which is when we filed our current rate case application), we were comfortable with our ability to meet the requirements of the Arizona SIP regional haze and MATS requirements because AEPCO's BART, as incorporated into the SIP, was deemed effective under operation of federal law. However, the EPA's July 2012 unexpected release of its FIP on Regional Haze surprised all utilities involved in the process. It rejected portions of ADEQ's SIP, including AEPCO's planned implementation. EPA's Final Rule in December 2012 would have required AEPCO to install by the end of 2017 selective catalytic reduction ("SCR") equipment on both ST2 and ST3 at a capital cost estimated to be approximately $200,000,000.

AEPCO realized it must act quickly in order to protect Apache Station's fate under the FIP. Fortunately, our prior planning and analysis enabled AEPCO to react and develop a plan of action promptly. Internal environmental, engineering and planning personnel worked together to formulate key conceptual alternatives to the implementation of the EPA's new FIP on ST2 and ST3 and to evaluate their costs and effectiveness. In addition, AEPCO hired a planning consultant to assist with developing order of magnitude costs to enable screening of FIP alternatives. AEPCO's initial options included what is discussed below as the AEPCO BART alternative proposal. It consists of converting one coal unit to gas-fired operation and installing selective non-catalytic reduction ("SNCR") technology on the other coal unit. Other evaluated alternatives ranged from potentially replacing both coal units with PPAs to replacing only one unit and converting the other to gas. The investigation also included the viability of sustaining both units on coal through 2035 with SCRs installed.

AEPCO reported the results of this screening effort to its Members by providing status reports at its Board of Directors monthly meetings and written reports to its Members directly. In December of 2012, AEPCO formed a Strategic Resource Planning Group consisting of key AEPCO staff, Member CEOs and staff as well as consultants. The consultants engaged by the Members are C.H. Guernsey & Company and GDS Associates.

Importantly – as it relates to Mr. Mazzini's suggestion of a more comprehensive study – this Group has since expanded its initial focus on screening FIP alternatives into a full strategic resource planning effort that first looked to verify the cost effectiveness of the AEPCO BART alternative proposal compared to other FIP options. This initial study effort included review of net present value alternatives through 2035, the useful lives of all Apache Station units in light of individual and aggregate Member loads – including PRM loads above their current capacities in AEPCO Resources – and the financial implications of resource decisions and developments (including potential rate impacts). The results of these initial reviews supported AEPCO's proposal. To finalize the investigations, the Strategic Resource Planning Group formed a

Technical Team of AEPCO and Member staff as well as their consultants to verify all the cost and modeling assumptions of the initial studies and to examine the sensitivity of the initial results to potential changes in future cost assumptions, such as the relationship between coal and gas costs and market prices.[8]

Meanwhile, in formally responding to the EPA regarding the FIP, AEPCO took two legal steps in early February 2013: (1) we filed for judicial review in the Ninth Circuit Court of Appeals challenging the legal bases for EPA's actions in respect to Apache Station and (2) we filed a Petition for Administrative Reconsideration with the EPA based on our BART alternative proposal.

Because these ongoing planning efforts positioned us to be able to respond promptly and thoroughly to the FIP, on June 6, 2013, the EPA granted reconsideration of the FIP – only nine days after AEPCO had filed its Supplemental Petition for Administrative Reconsideration. A copy of the correspondence reflecting the EPA decision to reconsider is attached as Exhibit RPK 4-2. The EPA's willingness to reconsider is an indication that the agency is seriously evaluating the viability of AEPCO's proposal.

MERITS OF THE BART ALTERNATIVE PROPOSAL

First and foremost, AEPCO's BART alternative proposal represents a substantial capital cost savings over that of the FIP. The capital cost for the proposal is roughly $30 million+ compared to the $200 million cost of the unrevised FIP. AEPCO expects to experience some higher operating cost for both units, as the SNCR technology involves adding chemicals to the flue gas to reduce NOx emissions and, for the other unit, natural gas prices are likely to be higher than the cost of coal. The Technical Team of the Strategic Resource Planning Group continues to work on identifying potential consequential indirect costs associated with our BART alternative proposal.

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[8] *See* Exhibit RPK 4-1, an exemplar Strategic Resource Technical Meeting Agenda.

Particularly responsive to Mr. Mazzini's concerns about the future of Apache Station, the BART alternative proposal is designed to maintain the viability of Apache well into the 2030s. That is consistent with and supportive of the Black & Veatch conclusion that "ST2 and ST3 can continue operation to 2035." First, by converting one unit to natural gas, AEPCO is able to realize substantial reductions in both SO_2 and PM. These reductions better correspond with the Arizona "Uniform Rate of Progress" demonstration, reducing the likelihood that AEPCO will be required to obtain additional SO_2 and PM reductions in the future. Second, by eliminating coal use in one unit, we (1) cut in half AEPCO's exposure to whatever future regulations might impact coal burning while (2) also retaining the current natural gas capacity that the Members can depend on to backup market purchases. At the same time, by keeping one unit on coal, AEPCO continues to reap the benefits of our STB victory and reduced coal prices discussed in Section 2 of this report.

Finally and importantly, the BART alternative proposal establishes a starting point for the Strategic Resource Planning Group's continuing analysis of how to work with our Class A Members to best to address their future load growth.

In conclusion, AEPCO recognizes that the future of our coal-fired units is threatened by increasing environmental regulation and other actions. Our ongoing planning, efforts and success quite recently and over the past six years confirm that we are responsive to and pro-active on these issues. If approved, the BART alternative proposal – though not ending Apache Station's dependence on coal – is a move that sustains ST2 and ST3's useful lives – further supporting the Black & Veatch analysis presented in Mr. Scott's direct testimony.

Based on the foregoing, the Commission should conclude that AEPCO – through its continued planning and successful efforts with the EPA to date as well as through the ongoing efforts of the Strategic Resource Planning Group – has already met and is continuing to perform the Apache Station analysis and planning suggested by Mr. Mazzini at page 3 of his report. Therefore, yet another study effort is not needed. Further, we ask that the Commission approve the revised depreciation rates stated in Exhibit PS-2 to Mr. Scott's direct testimony.

EXHIBIT RPK 2-1

EXHIBIT RPK 2-1: Apache Gross Generation by Year since 2000 and SRP Take

All Values in MWh unless shown otherwise

Unit	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
ST1	392,992	257,211	227,700	148,152	47,266	56,438	44,944	57,931	35,476	39,657	5,217	1,422	-
GT1	46,397	30,179	46,702	21,498	8,429	10,450	7,596	11,651	7,760	4,407	556	61	5
ST2	1,639,695	1,396,984	1,408,997	1,452,697	1,623,515	1,436,884	1,650,748	1,620,357	1,383,397	1,182,585	1,057,078	1,079,203	790,156
ST3	1,542,322	1,610,218	1,350,162	1,594,764	1,420,667	1,648,628	1,416,224	1,669,577	1,643,885	1,090,984	1,362,597	1,132,659	1,034,781
GT2	24,935	21,286	3,403	834	31	91	1,292	78	116	98	54	51	62
GT3	149,311	173,258	46,250	7,336	5,058	5,490	4,334	3,752	3,672	15,867	12,048	1,921	3,278
GT4			30,334	69,513	52,432	52,634	41,412	45,014	28,531	39,919	32,007	13,459	13,355
Totals	**3,795,652**	**3,489,136**	**3,113,548**	**3,294,794**	**3,157,398**	**3,210,615**	**3,166,550**	**3,408,360**	**3,102,837**	**2,373,517**	**2,469,557**	**2,228,776**	**1,841,637**
Event Desc.	CA -PX Sales	CA Market	PD Sale Exp							Coal Cost Inc			Mkt Price Dec

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Coal Gross	3,182,017	3,007,202	2,759,159	3,047,461	3,044,182	3,085,512	3,066,972	3,289,934	3,027,282	2,273,569	2,419,675	2,211,862	1,824,937
Max Coal	3,407,640	3,407,640	3,407,640	3,407,640	3,407,640	3,407,640	3,407,640	3,407,640	3,407,640	3,407,640	3,407,640	3,407,640	3,407,640
Cap. Factor	93.4%	88.2%	81.0%	89.4%	89.3%	90.5%	90.0%	96.5%	88.8%	66.7%	71.0%	64.9%	53.6%
SRP Take	836,392	774,583	634,770	799,064	819,785	835,925	839,180	857,398	855,273	421,805	490,249	-	-
SRP reduction		from 2002	(139,813)						from 2008	(433,468)	(365,024)	(855,273)	
SRP reduction as a percent										57.51%	60.08%	104.89%	
Station Diff from 2000:		(306,516)	(682,104)	(500,858)					(692,815)	(1,422,135)			
ST2 and ST3 Diff from 2000:		(174,815)	(422,858)	(134,556)					(154,735)	(908,448)			
Gas Diff				(366,302)					(538,080)	(513,687)			
Station Diff from 2002:				181,246									
ST2 and ST3 Diff from 2002:				288,302									
Gas Diff				(107,056)									
Station Diff from 2008										(729,320)	(633,280)	(874,061)	
ST2 and ST3 Diff from 2008:										(753,713)	(607,607)	(815,420)	
Gas Diff										24,393	(25,673)	(58,641)	
Station Diff from 2010												(240,781)	
ST2 and ST3 Diff from 2010:												(207,813)	
Gas Diff													
Station Diff from 2011													(387,139)
ST2 and ST3 Diff from 2011:													(386,925)
Gas Diff													(214)
Station Diff from 2009													(531,880)
ST2 and ST3 Diff from 2009:													(448,632)
Gas Diff													(83,248)
Class A Member Reductions, ST2 and ST3										(320,245)	(242,583)	39,853	(386,925)

EXHIBIT RPK 2-2

EXHIBIT RPK 2-2: AEPCO Coal Burns and Inventoried Coal Costs 2008 - 2012

Month	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Totals
Coal Tons	136,402.900	125,316.950	74,991.000	75,649.000	139,142.900	127,304.550	135,790.200	136,421.750	132,657.450	129,197.100	123,517.400	128,590.900	1,464,982.100
$/MMBtu	1.749	1.749	1.774	1.772	1.748	1.741	1.850	1.908	1.975	1.931	2.309	2.329	1.909
Weighting	238,558.793	219,184.179	133,043.685	134,042.441	243,220.071	221,670.969	251,233.163	260,254.709	262,019.071	249,450.993	285,178.303	299,468.646	2,797,325.023
$/MWH	$18.83	$18.43	$19.82	$19.92	$19.00	$18.34	$20.83	$22.87	$22.68	$21.76	$25.79	$25.10	$21.15

Month	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Totals
Coal Tons	124,546.550	112,632.700	65,396.550	60,961.900	81,288.150	88,748.650	117,980.100	115,756.550	98,940.650	104,576.150	63,917.100	92,976.350	1,127,721.400
$/MMBtu	2.474	2.561	2.696	2.821	2.874	2.896	2.944	2.954	3.004	3.054	3.073	2.982	2.851
Weighting	308,163.480	288,464.027	176,284.413	171,997.003	233,642.551	257,038.656	347,291.131	341,973.734	297,244.882	319,403.983	196,403.482	277,247.940	3,215,155.282
$/MWH	$27.09	$28.07	$28.25	$32.62	$32.73	$32.82	$31.96	$35.18	$34.80	$33.64	$34.46	$44.99	$32.92

Month	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Totals
Coal Tons	110,400.100	100,788.450	48,497.850	81,416.650	100,298.650	109,742.220	122,597.540	113,244.040	112,014.850	98,466.150	95,219.650	102,692.800	1,195,378.950
$/MMBtu	3.026	3.015	3.021	3.002	3.013	3.088	3.065	3.060	3.052	3.032	3.019	3.201	3.052
Weighting	334,112.475	303,840.541	146,491.699	244,434.256	302,221.150	338,936.830	375,713.399	346,481.995	341,820.337	298,514.532	287,469.408	328,760.844	3,648,797.465
$/MWH	$32.17	$31.96	$34.58	$33.14	$32.94	$31.31	$33.53	$34.12	$33.96	$36.02	$34.73	$33.54	$33.42

Month	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Totals
Coal Tons	106,295.400	86,097.050	61,776.250	51,182.100	79,115.600	103,433.750	115,640.050	125,082.450	107,105.250	96,918.350	75,608.850	88,533.650	1,096,788.750
$/MMBtu	3.204	3.199	3.198	3.197	3.248	3.237	3.242	3.254	3.237	3.233	3.224	3.124	3.220
Weighting	340,570.554	275,396.978	197,553.734	163,654.738	257,004.117	334,823.994	374,902.763	407,032.286	346,732.806	313,324.178	243,727.054	276,536.280	3,531,259.480
$/MWH	$35.07	$36.67	$37.59	$35.89	$38.40	$36.95	$36.19	$36.58	$37.06	$37.64	$37.69	$43.55	$37.36

Month	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Totals
Coal Tons	73,240.100	48,793.000	1,866.600	118.000	39,333.200	38,704.000	99,418.950	111,175.700	95,317.950	86,344.150	82,127.350	86,861.250	763,300.250
$/MMBtu	3.136	3.147	3.156	3.054	2.999	2.945	2.888	2.832	2.807	2.775	2.761	2.724	2.874
Weighting	229,696.596	153,541.783	5,890.545	360.430	117,970.600	113,982.373	287,150.428	314,836.836	267,532.590	239,584.635	226,725.106	236,593.973	2,193,865.896
$/MWH	$37.38	$37.99	$32.25	$30.56	$30.59	$38.78	$33.92	$31.90	$33.19	$32.57	$32.35	$31.53	$33.70

EXHIBIT RPK 2-3

Exhibit RPK 2-3

Historical Palo Verde Average Monthly 7x24 Prices[1]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Average
2008	$60.84	$63.71	$68.81	$80.21	$71.23	$85.65	$89.17	$67.44	$50.17	$39.72	$37.40	$42.11	$63.04
2009	$34.22	$30.36	$25.68	$23.79	$29.14	$23.65	$32.21	$28.88	$26.27	$33.72	$30.72	$42.84	$30.12
2010	$42.73	$41.74	$36.88	$32.00	$30.32	$29.20	$35.97	$35.05	$31.64	$29.62	$30.28	$31.69	$33.93
2011	$29.92	$30.15	$22.92	$27.90	$26.34	$26.14	$35.81	$35.08	$33.67	$30.17	$29.05	$29.05	$29.68
2012	$24.11	$23.30	$20.46	$18.73	$22.38	$23.82	$27.05	$33.91	$26.98	$30.29	$27.65	$27.77	$25.54

[1] Assumes 3,840 off-peak hours per year.

EXHIBIT RPK 2-4

Exhibit RPK 2-4-2008
Class A Member and AEPCO Monthly Purchases and Sale Energy for 2008

Determining Member Net Purchases vs Net Sales (MWh) see Note 1

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Load	180,158	163,747	175,870	178,474	206,757	270,647	280,805	277,411	231,389	183,378	154,343	178,510	2,481,490
less Member Billing Units	191,261	175,898	182,005	179,482	197,010	227,104	237,535	237,449	210,038	181,597	153,023	174,306	2,346,706
Sales	11,103	12,151	6,135	1,007	0	0	0	0	0	0	0	0	30,396
Purchases	0	0	0	0	9,747	43,543	43,270	39,962	21,351	1,781	1,321	4,205	165,180

Determining AEPCO Net Purchases or Net Sales (MWh) see Note (1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Billing Units	191,261	175,898	182,005	179,482	197,010	227,104	237,535	237,449	210,038	181,597	153,023	174,306	2,346,706
less Apache Class A Generation	167,262	158,232	46,996	54,627	166,109	159,844	170,543	180,587	173,696	155,418	138,485	149,458	1,721,257
Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchases	23,999	17,666	135,009	124,854	30,901	67,260	66,992	56,863	36,342	26,179	14,538	24,847	625,449

Determining Total Net Purchases or Net Sales (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Load	180,158	163,747	175,870	178,474	206,757	270,647	280,805	277,411	231,389	183,378	154,343	178,510	2,481,490
less Apache Class A Generation	167,262	158,232	46,996	54,627	166,109	159,844	170,543	180,587	173,696	155,418	138,485	149,458	1,721,257
Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchases	12,896	5,514	128,875	123,847	40,648	110,803	110,262	96,825	57,693	27,960	15,859	29,052	760,233

(1) Both economy purchases and economy sales can occur during any month; this measures only whether purchases or sales are dominant in a month.

Exhibit RPK 2-4-2009

Class A Member and AEPCO Monthly Purchases and Sale Energy for 2009

Determining Member Net Purchases vs Net Sales (MWh) see Note 1

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Load	170,249	153,889	170,301	178,469	232,801	239,124	304,210	292,558	238,125	178,451	156,881	184,745	2,499,802
less Member Billing Units	169,759	150,990	157,048	158,805	197,074	184,221	236,450	232,516	196,995	173,989	154,170	189,783	2,201,799
Sales	0	0	0	0	0	0	0	0	0	0	0	5,038	5,038
Purchases	490	2,900	13,253	19,664	35,727	54,903	67,759	60,042	41,131	4,462	2,711	0	303,042

Determining AEPCO Net Purchases or Net Sales (MWh) see Note (1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Billing Units	169,759	150,990	157,048	158,805	197,074	184,221	236,450	232,516	196,995	173,989	154,170	189,783	2,201,799
less Apache Class A Generation	152,091	143,097	72,380	86,535	115,134	138,854	207,277	186,644	151,965	144,259	92,176	121,079	1,611,489
Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchases	17,668	7,893	84,668	72,270	81,941	45,368	29,174	45,872	45,029	29,730	61,994	68,704	590,310

Determining Total Net Purchases or Net Sales (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Load	170,249	153,889	170,301	178,469	232,801	239,124	304,210	292,558	238,125	178,451	156,881	184,745	2,499,802
less Apache Class A Generation	152,091	143,097	72,380	86,535	115,134	138,854	207,277	186,644	151,965	144,259	92,176	121,079	1,611,489
Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchases	18,158	10,792	97,921	91,935	117,667	100,270	96,933	105,914	86,160	34,192	64,705	63,666	888,314

(1) Both economy purchases and economy sales can occur during any month; this measures only whether purchases or sales are dominant in a month.

Exhibit RPK 2-4-2010
Class A Member and AEPCO Monthly Purchases and Sale Energy for 2010

Determining Member Net Purchases vs Net Sales (MWh) see Note 1

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Load	176,816	152,985	166,784	166,534	196,643	258,663	296,669	276,471	237,859	179,080	161,004	172,500	2,442,008
less Member Billing Units	186,730	165,823	170,514	154,030	171,070	211,283	229,287	218,118	198,518	162,624	147,648	160,956	2,176,601
Sales	9,914	12,838	3,730	0	0	0	0	0	0	0	0	0	26,482
Purchases	0	0	0	12,504	25,573	47,380	67,382	58,353	39,341	16,456	13,357	11,544	291,890

Determining AEPCO Net Purchases or Net Sales (MWh) see Note (1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Billing Units	186,730	165,823	170,514	154,030	171,070	211,283	229,287	218,118	198,518	162,624	147,648	160,956	2,176,601
less Apache Class A Generation	141,404	123,234	60,143	97,508	148,968	162,209	172,227	162,259	158,710	141,795	137,429	150,462	1,656,347
Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchases	45,327	42,589	110,371	56,522	22,102	49,073	57,061	55,860	39,808	20,829	10,219	10,494	520,254

Determining Total Net Purchases or Net Sales (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Load	176,816	152,985	166,784	166,534	196,643	258,663	296,669	276,471	237,859	179,080	161,004	172,500	2,442,008
less Apache Class A Generation	141,404	123,234	60,143	97,508	148,968	162,209	172,227	162,259	158,710	141,795	137,429	150,462	1,656,347
Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchases	35,413	29,751	106,641	69,026	47,675	96,454	124,442	114,213	79,149	37,285	23,575	22,037	785,661

(1) Both economy purchases and economy sales can occur during any month; this measures only whether purchases or sales are dominant in a month.

Exhibit RPK 2-4-2011
Class A Member and AEPCO Monthly Purchases and Sale Energy for 2011

Determining Member Net Purchases vs Net Sales (MWh) see Note 1

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Load	180,374	164,356	170,086	179,839	204,752	269,235	296,716	302,376	234,797	182,070	157,783	190,932	2,533,316
less Member Billing Units	182,364	158,385	130,136	123,934	174,545	220,355	248,430	253,929	214,037	177,404	150,730	192,676	2,226,924
Sales	1,990	0	0	0	0	0	0	0	0	0	0	1,744	3,735
Purchases	0	5,970	39,950	55,905	30,207	48,880	48,286	48,448	20,761	4,666	7,053	0	310,127

Determining AEPCO Net Purchases or Net Sales (MWh) see Note (1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Billing Units	182,364	158,385	130,136	123,934	174,545	220,355	248,430	253,929	214,037	177,404	150,730	192,676	2,226,924
less Apache Class A Generation	191,593	149,445	107,080	91,103	139,680	184,068	213,084	228,307	193,124	170,686	134,067	156,909	1,959,144
Sales	9,229	0	0	0	0	0	0	0	0	0	0	0	9,229
Purchases	0	8,940	23,057	32,831	34,865	36,286	35,346	25,622	20,913	6,718	16,663	35,768	277,009

Determining Total Net Purchases or Net Sales (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Load	180,374	164,356	170,086	179,839	204,752	269,235	296,716	302,376	234,797	182,070	157,783	190,932	2,533,316
less Apache Class A Generation	191,593	149,445	107,080	91,103	139,680	184,068	213,084	228,307	193,124	170,686	134,067	156,909	1,959,144
Sales	11,219	0	0	0	0	0	0	0	0	0	0	0	11,219
Purchases	0	14,911	63,007	88,736	65,072	85,167	83,632	74,070	41,674	11,384	23,716	34,023	585,391

(1) Both economy purchases and economy sales can occur during any month; this measures only whether purchases or sales are dominant in a month.

Exhibit RPK 2-4-2012

Class A Member and AEPCO Monthly Purchases and Sale Energy for 2012

Determining Member Net Purchases vs Net Sales (MWh) see Note 1

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Load	175,135	160,983	177,382	189,857	234,149	283,264	286,905	304,843	234,899	185,053	155,994	180,802	2,569,267
less Member Billing Units	177,931	157,992	116,913	116,919	177,596	198,510	214,185	234,864	194,953	177,484	152,200	166,477	2,086,023
Sales	2,797	0	0	0	0	0	0	0	0	0	0	0	2,797
Purchases	0	2,991	60,470	72,937	56,553	84,754	72,720	69,980	39,946	7,569	3,795	14,325	486,041

Determining AEPCO Net Purchases or Net Sales (MWh) see Note (1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Billing Units	177,931	157,992	116,913	116,919	177,596	198,510	214,185	234,864	194,953	177,484	152,200	166,477	2,086,023
less Apache Class A Generation	137,515	125,434	54,337	56,634	127,111	135,830	174,308	202,891	165,678	150,056	142,133	151,448	1,623,375
Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchases	40,416	32,558	62,576	60,285	50,485	62,680	39,877	31,972	29,275	27,428	10,066	15,029	462,647

Determining Total Net Purchases or Net Sales (MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Load	175,135	160,983	177,382	189,857	234,149	283,264	286,905	304,843	234,899	185,053	155,994	180,802	2,569,267
less Apache Class A Generation	137,515	125,434	54,337	56,634	127,111	135,830	174,308	202,891	165,678	150,056	142,133	151,448	1,623,375
Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchases	37,620	35,549	123,046	133,223	107,038	147,434	112,598	101,952	69,221	34,997	13,861	29,354	945,892

(1) Both economy purchases and economy sales can occur during any month; this measures only whether purchases or sales are dominant in a month.

EXHIBIT RPK 2-5

EXHIBIT RPK 2-5

<u>CONFIDENTIAL</u>

EXHIBIT RPK 2-6

EXHIBIT RPK 2-6

<u>CONFIDENTIAL</u>

EXHIBIT RPK 3-1

To: Gary Grim, Chief Operating Officer

From: Charles Walling, Mgr. of Generation Engineering

Re: Evaluation of Long Term Standby for Apache Station CC1

Date: 4/05/2010

AEPCO's Apache Station Combined Cycle Unit #1 (CC1) experienced numerous boiler tube failures in the late summer and fall of 2009. Subsequent investigation has revealed that approximately $4.0M in boiler tube replacement will be necessary to return CC1 to reliable service. The high estimated cost of the necessary repairs, along with the current member contract expiration for CC1 in the year 2020 and the potential of a relatively low-cost source of replacement power beginning in the year 2015, have led AEPCO's staff to evaluate the impact to the members of placing ST1 into "long-term standby" status and replacing the capacity of CC1 with alternate resources. In this case, the long-term standby designation means that this unit would require more than 90 days to be brought on-line. For ease in reading of this report, the term "standby" has been used throughout to mean "long-term standby".

CC1 has a critical role in AEPCO's generation system in that it provides backup during the summer peak season in the event of a sustained outage of one of the coal-fired units. Currently, if CC1 is not available, members are at risk of involuntary load curtailment if a coal unit is lost during peak periods. This is due both to the limited availability of replacement power on short notice as well as to the limited ability to import replacement power on the Southwest Transmission Cooperative, Inc. (SWTC) system.

Although not a consideration for the purpose of this report, it is worth noting that decommissioning costs are on the horizon for CC1. Based on information provided by consultants, and costs experience by other utilities for similar units, we expect the cost of decommissioning CC1 to be on the order of $5M to $8M.

Executive Summary

This report is intended to provide general guidance as to the strategic and economic value of the concept of placing CC1 on standby. In addition to the net production cost, the cost and viability of transmission services to import the necessary capacity must be factored into the analysis. The cost of additional 75 MW of transmission capacity could be potentially be between $1M and $3M per year. This cost and availability are still unknown and have not been factored into this report.

The Resource Planning Department has performed an analysis of two standby scenarios of CC1 based on the potential O&M savings and replacement power costs. Current member contracts assume that CC1 does not provide energy beyond the year 2020. Resource Planning evaluated placing CC1 on standby at the end of year 2014. From a broad range of peaking and intermediate load resource alternatives, a 75 MW intermediate load resource, such as might be obtained by additional participation with the Southwest Public Power Resource Group (SPPR), was selected by the Strategist model as the most economic alternative to replace CC1. Additionally, the placement of CC1 on standby in 2011 was evaluated by assuming the purchase of a 75 MW "super peak" (8 hours per day, 7 days per week) purchase power agreement (PPA) until 2015 when the new intermediate load resource would be available.

Based on the adjusted cumulative net present value output (attached) of the PROMOD production cost model, placing CC1 on standby in 2014 is estimated to cost the members an additional $43M in increased production costs over the study period. Placing CC1 on standby in 2011 is estimated to cost the members approximately the same amount ($43M) over the same study period. The additional cost of placing CC1 on standby in the years 2011 to 2014 reflects the lack of economic dispatch capability of the fixed super peak PPA as compared to CC1. In the years 2015 to 2020, AEPCO still has a seasonal peaking need which appears to be a good fit for CC1. In these years, PROMOD indicated a $10M (8%) increase, beginning in 2015, to AEPCO's total net annual production costs due to replacing CC1 by the 75 MW intermediate load resource. The low fixed cost for CC1 more than offsets the fuel savings of a more efficient newer unit when used for seasonal peaking purposes in this timeframe.

Even assuming that power import capacity can be obtained, the results of this analysis indicate that a $4.0M investment in CC1 boiler repair and 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.

Background

Combined Cycle Unit # 1 consists of a 10 MW GE Frame 5 gas turbine which exhausts into a B&W boiler for which the gas turbine exhaust provides a portion of combustion air and supplemental heat. The B&W boiler in turn drives a 75 MW steam turbine generator. This equipment was placed in service in the early 1960s to replace various diesel generators distributed throughout the AEPCO system.

In recent years AEPCO has relied on CC1 to provide capacity and energy on a seasonal basis. No staff is dedicated to the operations and maintenance of CC1. Operations attendance and associated cost for this unit is minimal. A controls upgrade in 2002 allows CC1 to be remotely operated from the ST2/ST3 control room by the same operator that is running either ST2 or ST3.

Until 2009, maintenance costs have been minimal on CC1 as well. In the late summer of 2009, continued failures on boiler water wall tubes prevented reliable operation of the unit and resulted in considerable maintenance expense. Roughly $400k has been spent in capital and O&M expense in 2009-2010 to repair and investigate boiler tube failures. It has now been determined that wholesale replacement of major sections of the boiler, at an approximate cost of $4.0M will be required to return CC1 to reliable service.

Otherwise, CC1 is in good condition. The steam turbine was overhauled in early 2009 and the gas turbine was overhauled in early 2010. Assuming that the boiler is repaired and returned to service, CC1 is expected to operate on a seasonal basis for the remainder of this decade without further overhauls. The highest maintenance system for CC1 is expected to be the cooling tower. This cooling tower was replaced in 1998. With continued inspection and repairs, the cooling tower should also provide reliable service through the end of the decade.

Analytic Approach

A base case and two alternatives were considered for this analysis. All cases assumed that all-requirements members (ARM) and partial-requirements members (PRM) are at their allocated capacity. Additionally, all cases are based on the latest Board approved medium economic load forecast scenario. The load forecast takes into account an expected effect of renewable and energy efficiency requirements. All study and report costs are based on 2010 dollars.

Note that 75 MW purchases were selected to replace the 82MW net capacity of CC1. The model will take any additional energy needed from market purchases.

1) <u>2020 - Operational Assumptions (base case):</u>

   a) Continued O&M cost for CC1 through 2020 based on historical averages of $300k per year with an additional $100k allowance for unplanned expenses. An additional allowance was included of $250k total for capital items over the entire period. This maintenance estimate is a minimalistic approach based on the assumption, for the purpose of this study, that the unit would not be operated beyond 2020.

   b) No additional overhauls or associated costs are expected for CC1 in this scenario.

   c) An additional capital cost of approximately $4.0M for boiler tube work in 2010 was included for this case in order to achieve the level of reliability required.

   d) For solution to the load forecast, this case includes an additional 125 MW resource added in 2015.

2) <u>2014 - Standby Assumptions:</u>

   a) 82 MW capacity from CC1 becomes unavailable December 31, 2014.

      i) Annual O&M savings – approximately $904k per year.

   b) Additional 75 MW of long-term resource capacity is available in 2015 to replace CC1.

      i) Heat rate comparable to 500 MW 2x1 combined cycle.

      ii) Additional capacity and fixed O&M charge – approximately $7M per year.

3) <u>2011 - Standby Assumptions:</u>

   a) Additional 75 MW of super-peak purchase capacity is available in 2011.

      i) 8 hours X 7 days for the summer peak season.

   b) Additional 75 MW of long-term resource capacity is used in 2015 to replace PPA.

This analysis was performed using both the PROMOD production cost model and the Strategist optimal generation expansion model. These models are configured with AEPCO's existing resources as well as the latest approved member medium economic load forecast. PROMOD is a detailed model that is intended to simulate economic dispatch of units on an hourly basis and determine the resulting production cost. Strategist is a less detailed model that is typically used to evaluate future resource options and select the best plan of new resources that fit a given load forecast profile. Strategist inputs include the installed cost and performance figures of a variety of plant construction and PPA options. The model will then calculate the annual production cost for different combinations of resources and installed years and identify the lowest cost combinations.

For the purpose of this analysis, the cost of a seasonal super peak PPA configured to replace the CC1 capacity was added for the years 2011 to 2015. This PPA would provide 75 MW of capacity during the summer season, 8 hours a day, 7 days a week (84 GWh). The estimated cost for this short-term PPA was obtained by AEPCO's Power Scheduling and Trading group and is based on a indicative pricing provided by Powerex. Based on the requirements, the total annual cost of this PPA would be about $81 per MWh in 2011 or roughly $6.8M per year. For years 2015 and after, Strategist was used to select the least cost alternative resource from a variety of peaking and intermediate load alternatives. Based on the Strategist results, the short-term PPA was replaced in 2015 by a year-round, long-term resource (an additional 75MW piece of larger SPPR resource) at a cost of roughly $7M per year plus fuel.

The fixed costs of AEPCO's existing units, such as depreciation, O&M, taxes, etc., are not normally included in the models since these are considered to be "sunk" costs to which the members are committed whether the units are operating or not. For the purpose of this analysis, the estimated fixed cost of CC1 was added to each model output only for those years that the unit was not place into standby mode. This estimated fixed cost included $4.0M for additional boiler maintenance that is expected to be necessary in 2010 in order to have CC1 reliable for the 2010 peak season. This yielded a relative cost for each case that reflects the savings resulting from placement into standby mode.

The initial results of the Strategist model indicated that continued operation of CC1, even with additional major capital investment, would result in the lowest overall cost of production. Since Strategist does not perform detailed hourly dispatch modeling, the PROMOD model was used to further refine the relative cost difference between the three evaluated cases and to validate the initial results of Strategist.

Analysis Results

<u>2020 - Operational (Base Case)</u>

The net present value cost over the 2011 to 2020 study period for the base case scenario was $913M.

<u>2011 - Standby</u>

This case resulted in a net present value cost ($956M) higher than that of the base case (($913) over the study period. During the 2011 to 2014 years, the short term PPA results in energy that must be paid for whether it is needed or not. This results in occasions where the model will reduce load on the more economical coal-fired units in order to take power from the PPA. Additionally, while CC1 has a high heat rate and a high cost per MWh, its overall annual cost is low simply because its fixed costs are low and it does not run very much. The super-peak PPA, on the other hand, has a slightly lower cost per MWh. However, since AEPCO must pay for the super peak PPA whether it is needed or not, the net result is a higher production cost in comparison to continued operation of CC1.

During the 2015 to 2020 years, this super peak PPA is assumed to be replaced by a 75 MW tolling agreement, which would provide year round capacity at a cost of roughly $7M per year plus fuel (fuel to be provided by AEPCO). This estimate is based on costs comparable to recent proposals received by the SPPR group and assumes that this is a 75 MW participation (above that in which AEPCO would otherwise participate) in a modern and efficient combined cycle unit. This unit's much lower heat rate results in a lower cost for fuel over that of CC1. However, the unit is not dispatched enough for the fuel savings to offset the unit's effective capacity charge of $6.9M per year. This effective capacity charge is the difference between the actual charge of $8M per year and the savings of roughly 0.9M per year resulting from placing CC1 on standby.

2014 - Standby

This case resulted in essentially the same net present value production cost ($965M) over the study period as the 2011 case. The 2014 standby scenario was based on continued operation of CC1 until the end of the year 2014 and then replacing it with the same 75 MW tolling agreement described under the 2011 scenario. As in the 2011 case, the unit is not dispatched enough for the fuel savings to offset the replacement unit's effective capacity charge of $6.9M per year.

Additional Factors

Opportunity Purchases – The availability of capacity from CC1 provides the ability for the power marketers to make opportunity purchases of low-cost non-firm power. If CC1 is on-line, the marketers are able to reduce load on CC1 when lower cost power is available. If the non-firm power is dropped, AEPCO can simply ramp CC1 back to full load with no loss in reliability. This type of opportunity purchasing is reflected in the model output.

Transmission – No final determination has been made as to whether transmission capability exists to import power to cover the loss of a coal-fired unit in the summer season. Assuming that this capability can be created on short notice with contractual methods, the cost of firm import capacity could add between $1M and $3M to the cost of either a short-term PPA or to a long-term resource.

Summary

Based on the adjusted output of the PROMOD production cost model, the cumulative net present value of these three cases was estimated to be $913M, $956M, and $956M respectively. In other words, placing CC1 on standby at the end of year 2014 is estimated to cost the members an additional $43M over the study period, and placing CC1 on standby in 2011 is estimated to cost the members approximately the same amount. The $43M additional cost is a result of the economic dispatch capability of CC1 as compared to a fixed PPA, and also to the relatively low fixed costs of CC1 as compared to a purchase of additional combined cycle capacity. This low fixed cost for CC1 more than offsets the higher fuel efficiency of a newer unit for seasonal peaking purposes.

The results of this analysis indicate that a $4.0M investment in CC1 boiler repair and the continued use of CC1 (including normal O&M and capital expenses) for reserve and seasonal peaking capacity will be the most economic alternative, of those evaluated, for the members.

PROMOD Modeling

Note Ref:	CC1 Operational 2020 ($000) [125 MW SPPR Take]	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1)	Total Production Costs	102,066	109,741	112,123	117,627	125,160	125,483	131,551	135,001	140,092	144,511
2)	CC1 Depreciation	228	228	228	228	228	228	228	228	228	228
3)	CC1 Property Taxes	80	80	80	80	80	80	80	80	80	80
4)	Maintenance Expense	400	400	400	400	400	400	400	400	200	200
5)	2009 Major Overhaul (3.5M less paid @6%)	466	466	466	466	466	466	466	466	194	-
	Major Boiler Repair ($4M less paid @6%)	533	533	533	533	533	533	533	533	533	222
	2009-2015 Capital	250	-	-	-	-	-	-	-	-	-
	Entegra Property Taxes					383	366	349	338	319	295
	Entegra Insurance					142	146	150	155	160	164
	Total ($000)	**104,023**	**111,449**	**113,830**	**119,334**	**127,393**	**127,702**	**133,758**	**137,201**	**141,805**	**145,700**
	Net Present Value of Total Annual Expenses ($000)	98,135	99,189	95,574	94,524	95,195	90,025	88,957	86,081	83,934	81,358
	Net Present Value 2011 - 2020 ($000)	**912,972**									

Note Ref:	CC1 Standby - 2014 ($000) [125 MW + 75MW Sppr Take]	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Total Production Costs	102,066	109,741	112,123	117,682	136,349	137,520	140,641	145,910	152,278	156,893
2)	CC1 Depreciation	570	570	570	570						
3)	CC1 Property Taxes	80	80	80	80						
4)	Maintenance Expense	400	400	400	400						
	2009 Major Overhaul (3.5M less paid @6%)	848	848	848	848	-	-	-	-	-	-
	Major Boiler Repair ($4M less paid @6%)	1,056	1,056	1,056	1,056	-	-	-	-	-	-
	2009-2015 Capital	250	-	-	-	-	-	-	-	-	-
	Entegra Property Taxes					613	585	558	541	510	471
	Entegra Insurance					227	234	241	248	255	263
	Total ($000)	**105,271**	**112,696**	**115,078**	**120,638**	**137,189**	**138,339**	**141,440**	**146,698**	**153,043**	**157,627**
	Net Present Value of Total Annual Expenses ($000)	99,312	100,299	96,622	95,556	102,516	97,523	94,066	92,040	90,586	88,018
	Net Present Value 2011 - 2020 ($000)	**956,539**									

Note Ref:	CC1 Standby 2011 ($000) [as above + 75 MW Super Peak PPA 2011-2014]	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Total Production Costs	103,151	111,230	113,518	118,935	136,346	137,520	140,641	145,910	152,278	156,893
	Sub Total ($000)	103,151	111,230	113,518	118,935	136,346	137,520	140,641	145,910	152,278	156,893
2)	CC1 Depreciation	2,281									
6)	2009 Major Overhaul (3.5M less paid @6%)	3,109	-	-	-	-	-	-	-	-	-
	Major Boiler Repair ($4M less paid @6%)	-	-	-	-	-	-	-	-	-	-
	2009-2015 Capital	-	-	-	-	-	-	-	-	-	-
	Entegra Property Taxes					613	585	558	541	510	471
	Entegra Insurance					227	234	241	248	255	263
	Total ($000)	**108,541**	**111,230**	**113,518**	**118,935**	**137,187**	**138,339**	**141,440**	**146,698**	**153,043**	**157,627**
	Net Present Value of Total Annual Expenses ($000)	102,398	98,995	95,312	94,208	102,514	97,523	94,066	92,040	90,586	88,018
	Net Present Value 2011 - 2020($000)	**955,660**									

Notes:
1) Greatest differential is in the 2015 thru 2020 timeframe
2) CC1 Depreciation is considered common to all cases
3) CC1 Property Taxes are assumed to be insignificant after retirement
4) Maintenance Expenses are based on $300k/yr planned and $100k/yr unplanned maintenance which is consistent with historical costs
5) 2020and 2014 standby - Capital and Major Maintenance includes payoff of $3.5M 2009 Overhaul costs as well as $4.0M boiler tube repair
6) 2011 Standby - Capital and Major Maintenance includes payoff of $3.5M 2009 Overhaul costs since $3.5M boiler tube repair costs are avoided
7) Updated NPV calcs to 2010 basis per D Lindeman. 4/1/10

EXHIBIT RPK 3-2

Submitted By: B. Brown
Reviewed By: S. Whitley

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

EXECUTIVE/STAFF SUMMARY

(Board Meeting of April 14, 2010)

<u>**TITLE OF ITEM**</u>: Approval of Capital Project 5-01185, ST1 Furnace Tube Replacement.

<u>**BOARD ACTION RECOMMENDED**</u>: Management recommends Board approval of this non-budgeted capital project to replace the additional and necessary ST1 furnace tubing at Apache Station in the amount of $3,900,000.

<u>**BACKGROUND**</u>: This item has not previously been presented to the Board for formal action/approval. The subject of ST1 furnace tube failures has been discussed several times with the Board in recent months. Also, the Board approved a capital project to replace certain sections of the ST1 furnace tubing in September 2009 for the estimated cost of $425,000. Arizona Electric Power Cooperative, Inc. (AEPCO) has spent a total of $338,428 of this budgeted amount and has closed this project.

During the summer of 2009, the ST1 Boiler experienced three consecutive water wall tube failures. After the third failure, AEPCO staff decided to perform a furnace water wall tube inspection. The inspection revealed many areas where high heat, internal deposits, and age caused pitting and thinning of fire-side tube wall thickness. AEPCO replaced what it anticipated was the worst tubing as part of the September 2009 approved project. Subsequent unit start-up revealed that the furnace tube thinning and cracking were more severe than previous testing indicated. One of these tubes failed on the cold side of the tube, blowing outward from the boiler exterior. A steam leak such as this, to the outside of the boiler, is an immediate and potentially severe hazard to the safety of personnel who may be on walkways or platforms in the vicinity of the leak. All previous failures blew from the fireside of the tubes toward the boiler interior.

The single cold side tube failure caused AEPCO engineering to seek evaluation from the boiler original equipment manufacturer (OEM). This evaluation involved more sophisticated inspection techniques since personnel safety became the most pressing concern. As a result of further analysis by the OEM, the OEM is recommending significant boiler tube replacement that is included in the scope of work of this project. The percentage of furnace tube replacement is now estimated at 85%.

The ST1 Boiler was placed in service in 1964. The unit has performed well over its 46-year life that includes summer peaking and recent daily start-up operation.

Proposals for the installation of the ST1 furnace tubes were requested from five bidders on March 12, 2010 in accordance with Board Policy 7-10, <u>*Capital Project and Preliminary Survey Approvals and Procurement for Capital Projects and Preliminary Surveys*</u>, and 7 CFR 1726. Rural Utilities Service (RUS) Equipment Contract Form 200 was used to solicit bids. Of the five bids sought, two bids were received on April 1, 2010.

The final bid results are as follows:

Bidder	Base Bid	Evaluated Total
Alstom Power, Inc.	did not bid	N/A
Babcock & Wilcox	did not bid	N/A
Epic West, Inc.	$1,955,124	$1,955,124
Foster Wheeler Group	did not bid	N/A
TEI Construction Services, Inc.	$1,504,790	$1,546,549

Of the proposals received, only Epic West, Inc. (Epic) and TEI Construction Services, Inc. (TEI) provided bids responsive to the RUS terms and conditions. TEI was the low evaluated bidder and it is Management's recommendation that the ST1 Furnace Tube Replacement, Specification 5-01185.SP-2, be awarded to TEI in the amount of $1,546,549.

BUDGET AND FINANCIAL CONSIDERATIONS: The need for this capital project was neither anticipated during the 2010 budget process nor included in the 2010 capital budget. The project cash flow has been reviewed with the Finance Department and is expected to be supported with general funds and included in the next construction work plan for possible reimbursement with Rural Utilities Service (RUS) loan funds. Due to the nature of the replacement, and the limited remaining life of this unit, this project may not be a candidate for RUS loan funds.

The estimated project cost includes $1,391,000 for boiler tube material, $1,546,549 for demolition of existing tubing and installation of new tubing, $250,000 for inspection and additional non-destructive testing, $250,000 for new insulation and lagging, $371,000 for contingency (10%) and $91,451 for interest during construction and project management. The requested budget for this project is based on an estimated cost of $3,900,000.

ALTERNATIVES CONSIDERED: ST1 will not be available as a reliable/safe generation resource until this work is completed. The initial alternative considered was that of retiring both ST1 and GT1 (together as combined cycle unit CC1) from service and replacing their capacity with purchase power agreements. CC1 typically provides only 1-2% of the energy from Apache Station. However, if CC1 is unavailable, AEPCO would need to replace it immediately with a short term (5 year) power purchase agreement (PPA) of 85 MW. The effect on AEPCO's overall production cost of a replacement PPA would exceed the cost of the repairs and continued operation to CC1. This alternative will be reviewed in greater detail in a separate report to be presented to the Board.

The material to be used for tube replacement is standard for new boilers of this type. However, it is an upgrade from the original in both alloy and fabrication simply due to improvements in technology.

Various alternates were considered in respect to the overall quantity of boiler area to be replaced. These were, approximately, 45%, 65%, and 85% of the total boiler area. As the value of ST1 lies in its continued availability, the alternative to replace 85% of furnace tubing was selected as the most likely to provide the overall lowest production cost over the remaining life of the unit.

CONCLUSION: It is the conclusion of Management that approval of this capital project will be in the best interest of Arizona Electric Power Cooperative, Inc. and its member-consumers.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

The following resolution was adopted at a **regular meeting** of the Board of Directors of Arizona Electric Power Cooperative, Inc. (AEPCO), held in Benson, Arizona on April 14, 2010.

RESOLUTION

WHEREAS, *Arizona Electric Power Cooperative, Inc. (AEPCO) generation unit ST1 has significant water wall tube damage, because of age and other factors, to a large portion of the furnace; and*

WHEREAS, *tube damage has left the unit highly prone to tube failures that have caused the suspension of ST1 operation; and*

WHEREAS, *subsequent failures are a risk to personnel safety because a recent tube rupture blew high pressure steam and debris into an operation and maintenance walkway and platform; and*

WHEREAS, *the loss of a coal unit (ST2 or ST3) during the summer peak season could result in a member load curtailment due to the lack of transmission import capability if ST1 remains unavailable; and*

WHEREAS, *AEPCO staff has determined that it is cost effective to restore ST1 to safe and reliable operation, by replacing the damaged tubes, rather than enter into a purchase power contract to replace the capacity of ST1; and*

WHEREAS, *AEPCO Management recommends capitalization of this work and approval of Project 5-01185, ST1 Furnace Tube Replacement in the estimated total installed cost of $3,900,000; and*

WHEREAS, *five bids were solicited for the installation of ST1 Furnace Tube Replacement (Specification 5-01185.SP-2) in accordance with Rural Utilities Service (RUS) requirements and two bids were received; and*

WHEREAS, *TEI Construction Services, Inc. (TEI) is the low evaluated bidder and Management recommends the award of a contract to TEI in the amount of $1,546,549 for the installation of the ST1 Furnace Tube Replacement, Project 5-01185; and*

WHEREAS, *the Board of Directors has reviewed the recommendation of Management and deems it to be in the best interest of AEPCO and its member-consumers to approve the contract for the installation of ST1 Furnace Tube Replacement (Specification 5-00998.SP-2) to TEI;*

NOW, THEREFORE, BE IT RESOLVED, *that the Board of Directors of Arizona Electric Power Cooperative, Inc. hereby approves Project 5-01185, ST1 Furnace Tube Replacement in the estimated amount of $3,900,000; and*

BE IT FURTHER RESOLVED, *that a contract for the installation of ST1 Furnace Tube Replacement (Specification 5-01185.SP-2) be awarded to TEI Construction Services, Inc. in the amount of $1,546,549; and*

BE IT FURTHER RESOLVED, *that the Board of Directors of AEPCO authorizes Management to undertake any additional actions as may be necessary to effectuate the purpose and intent of this resolution.*

I, Thomas N. Powers, do hereby certify that I am Secretary of AEPCO, and that the foregoing is a true and correct copy of the Resolution adopted by the Board of Directors at a **regular meeting** held on April 14, 2010.

Thomas N Powers

Secretary

(seal)

EXHIBIT RPK 3-3

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:

65 Main Street
Quentin, Pennsylvania 17083

(717) 270-4500 (voice)
(717) 270-0555 (facsimile)
Admin@LibertyConsultingGroup.com (e-mail)

July 30, 2010

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

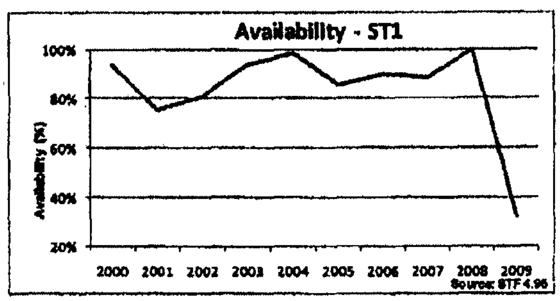
	ST2		ST3	
	2009	2010 thru May	2009	2010 thru May
Availability	89.5	72.0	80.7	93.4
Capacity Factor	69.3	50.3	63.4	76.3
CF while available	77.4%	69.9%	78.6%	81.7%

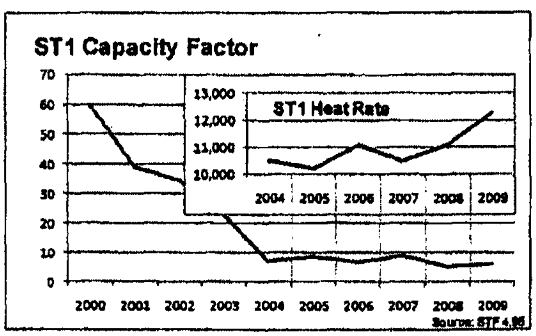
Source: STF 4.59 and 5.20

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.

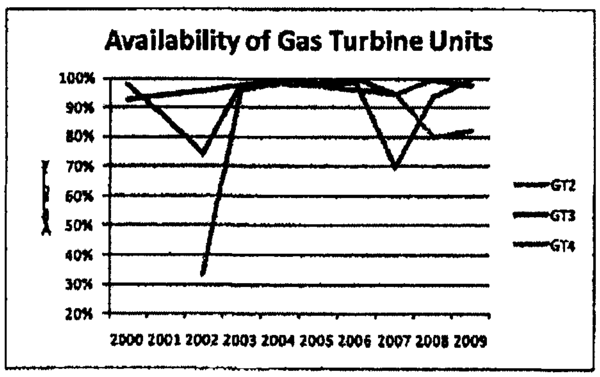
Factors such as these raise the question of the appropriateness of continued operation of and investment in CC1. Management has asked that question as well, commissioning a study completed April 5, 2010.[45] The study compared continued operation through 2020 versus placing the unit in "long term standby." 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.

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)			
		Estimate	Actual
Unit	Project	STF 10.1	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	1,280	948
ST2/3	Coal handling upgrades	1,134	906
ST2/3	Mercury CEM	598	889
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.

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

EXHIBIT RPK 3-4

From: Patrick Ledger <pledger@aepco.coop>
Sent: Thursday, May 16, 2013 11:35 AM
To: 'mikepearce@dvec.org'; 'Tyler Carlson'; 'Creden W. Huber'; 'Kevin Short'; 'Vin Nitido'; 'Steve Lines (slines@gce.coop)'
Cc: Division Manager Group
Subject: Summer 2013 / CC1 Operation Proposal
Attachments: CC1 Cost Analysis.pdf

Importance: High

All:

At the Arizona Electric Power Cooperative, Inc. (AEPCO) Board meeting on March 13, AEPCO Staff proposed to restrict operations of Apache Station's gas-fired Combined Cycle Unit (CC Unit) (82 MW total capacity, with 10 MW of GT 1 and 72 MW of ST 1) for the upcoming summer to about one week of testing in late June. The testing is being done to ensure the CC Unit is in good working order. Otherwise, the approach is the same as was implemented with Member approval in the last two years. Specifically, AEPCO would otherwise keep the CC Unit off-line until or unless market or other Apache unit operating situations dictate its operations, at the discretion of the Director of Energy Services, Mr. Walter Bray.

The proposed approach recognizes and would take advantage of the anticipated depressed summer power market prices, allowing savings in your future Purchased Power and Fuel Adjustment Clause (PPFAC). An estimate of the hourly, daily, monthly and seasonal savings that might be achieved under this proposal is shown in the attached spreadsheet.

However, the proposed approach also entails some potential risks from a reliability perspective which, if unanticipated higher market prices or curtailed coal-fired operating conditions occur. Such conditions could actually result in higher energy costs for some short periods of time, primarily because it could take some about 24 hours to get the CC Unit fully operational. The purpose of this e-mail is to advise you of this risk, and to seek your approval of the proposed concept notwithstanding the risk.

In addition, AEPCO's ability to operate CC Unit this summer is affected by a temporary emissions mandate effective through next year. The mandate restricts CC Unit to less than two months at full daytime load. If we avoid CC Unit operations this summer, we expect to have the full summer period available for CC Unit operations next year.

AEPCO Staff believes that the current summer power prices present an opportunity to reduce your PPFAC costs resulting from operations this summer (which would primarily show up in the PPFAC beginning October 2013), and believes that the proposed procedure involving the CC Unit is a reasonable approach. In order to implement that procedure, however, AEPCO believes it needs the unanimous approval of its Class A Members of this proposal, and acceptance of the potential risks.

If AEPCO is to implement this procedure in July and August, it will need the acceptance of all Class A members prior to that time, otherwise AEPCO under the wholesale power contract would be required to operate the CC Unit starting shortly before or shortly after July 4 and continue operating the CC Unit through the end of August.

If you concur in AEPCO's proposal regarding the CC Unit as outlined above, and your cooperative is willing to take the associated risks, please so indicate by "reply to all" to this e-mail once you have your needed approvals.

If you have any questions or concerns, please call me at your earliest convenience.

Thank you,

Patrick

Patrick F. Ledger
CEO
Arizona Generation and Transmission Cooperatives
P.O. Box 2165
Benson, Arizona 85602
Phone: (520) 586-5110
Cell: (520) 559-4449
pledger@ssw.coop

Additional Cost to operate CC by month:		
CC Unit operating at 20 MW for 12 hours, 75 MW for 12 hours, 5 days a week excluding Saturday, Sundays and Holidays		
Month	$	MWH
July	$67,368.40	25,080
August	$10,947.20	25,080
Total	$78,315.60	50,160

Cost by Member		
CARM	11.4%	$8,927.98
MEC	35.8%	$28,036.98
SSVEC	31.7%	$24,826.05
Trico	21.1%	$16,524.59
Total	100.0%	$78,315.60

Cost information is based on Power and Gas prices as of May 15, 2013, as follows:

	Power		Natural Gas				CC Unit loading and energy rate	
	Palo Verde		Basin		Natural Gas	Natural Gas	20 MW	75 MW
Month	On-peak	Off Peak	Permian	San Juan	Average	Delivered	$/MWh	$/MWh
Jul	$49.250	$30.100	$3.941	$3.906	$3.92	$4.30	$62.78	$45.64
Aug	$52.300	$30.680	$3.977	$3.936	$3.96	$4.34	$63.36	$46.06

EXHIBIT RPK 3-5

Exhibit RPK 3-5

Class A Member Capacity In and Use of AEPCO Resources for 2011 and 2012

Determining Member Surplus/(Deficit) Allocated Capacity to Coincident Peak - MW

2011	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Allocated Capacity	517	517	522	527	576	577	577	577	576	566	517	517	6,565
Member Coincident Peak	325	392	288	344	429	590	599	590	549	407	276	334	5,123
Surplus/(Deficit) Allocated Capacity	192	125	234	183	147	(13)	(22)	(13)	27	158	241	182	1,442

Determining Member Surplus/(Deficit) Allocated Capacity to Coincident Peak - MW

2012	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Member Allocated Capacity	517	517	522	527	586	586	587	587	586	575	517	517	6,624
Member Coincident Peak	303	299	298	424	508	576	580	618	481	429	301	332	5,147
Surplus/(Deficit) Allocated Capacity	214	218	224	103	78	10	8	(31)	105	147	215	185	1,477

EXHIBIT RPK 4-1

Strategic Resource Technical Meeting Agenda
Tuesday, May 21, 2013, 9:00 a.m.

Grand Canyon State Electric Cooperative
2210 South Priest Drive
Tempe, AZ 85282

AEPCO Member Update Meeting

1. Review Action Items from April 24 meeting
2. Environmental Protection Agency (EPA) Update
3. Role and composition of the technical group
4. Discuss the ACES' gas vs coal vs market price forecasts
5. Review the individual PRM and CARM loads vs resources shortfall forecasts
6. Review effect of delaying contract end dates of CC1, GT2 and GT3 on individual member's L&R analysis of extension of such dates through 2035
7. Discuss Strategist modeling application to individual member's L&R vs aggregate members' L&R and usefulness of such analyses
8. Discuss PRM questions regarding cost assumptions used by AEPCO in its Strategist model, financial model and spreadsheets (to get consensus for future modeling purposes)
9. Next Meeting's Deliverables
10. Other

EXHIBIT RPK 4-2

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

OFFICE OF THE
REGIONAL ADMINISTRATOR

JUN 0 6 2013

Mr. Eric L. Hiser
Jorden Bischoff & Hiser, P.L.C.
7272 E. Indian School Road, Suite 360
Scottsdale, Arizona 85251

Dear Mr. Hiser:

The U.S. Environmental Protection Agency (EPA) has received the petition you submitted on February 4, 2013 on behalf of Arizona Electric Power Cooperative (AEPCO), seeking reconsideration and a stay of effectiveness of certain elements of EPA's final rule entitled "Approval, Disapproval and Promulgation of Air Quality Implementation Plans: Arizona; Regional Haze State and Federal Implementation Plans" as it applies to the Apache Generating Station (Apache), 77 FR 72512 (Dec. 5, 2012). We have also received the supplement to the petition that you submitted on May 29, 2013, which sets out an alternative to the determinations of Best Available Retrofit Technology (BART) for Apache Units ST2 and ST3 reflected in that rule.

In response to your petition, EPA is granting partial reconsideration of our final rule pursuant to section 307(d)(7)(B) of the Clean Air Act (CAA), 42 U.S.C. § 7607(d)(7)(B). In particular, in response to AEPCO's proposed alternative to BART for Apache Units ST2 and ST3, we are granting reconsideration of the emission limits for nitrogen oxides (NO_X), sulfur dioxide (SO_2) and particulate matter (PM) at those units. In addition, we are granting reconsideration of the compliance methodology for NO_X in our final rule as it applies to Apache Units ST2 and ST3. Finally, we are granting reconsideration of the provisions of our final rule concerning Apache Units ST1 and GT1 in order to clarify the circumstances under which the BART limits for ST1 apply to these units.

Accordingly, EPA plans to publish a notice of proposed rulemaking seeking comment on an alternative to BART and a revised compliance methodology for Apache Units ST2 and ST3. As part of this notice, we also intend to propose and seek comment on a clarification to the regulatory text concerning the applicability of BART limits to ST1 and GT1.

If you have any questions regarding the reconsideration process, please contact Charlotte Withey at (415) 972-3915 or Lea Anderson at (202) 564-5571. We thank you for your continued interest in this rule and look forward to hearing from you during the reconsideration process.

Sincerely,

Jared Blumenfeld

cc: Mr. Eric Massey, Arizona Department of Environmental Quality
Mr. Joseph P. Mikitish, Arizona Attorney General's Office
Mr. Michael Hiatt, Earthjustice
Arizona Congressional Delegation