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NEW APPLICATION

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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
DOCKET CONTROL

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TOM FORESE

Arizona Corporation Commission
DOCKETED
NOV 13 2015
DOCKETED BY

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR AUTHORIZATION TO INCUR DEBT AND SECURE LIENS IN ITS PROPERTY TO FINANCE ITS CONSTRUCTION WORK PLAN	Docket No. E-01773A-15-0389 **APPLICATION**

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

Pursuant to A.R.S. §§ 40-285 and 40-301, *et seq.*, Arizona Electric Power Cooperative, Inc. ("AEPCO" or the "Cooperative") in support of its Application states as follows:

1. AEPCO is an Arizona non-profit electric generation cooperative which supplies all or most of the power and energy requirements of its five Arizona Class A member distribution cooperatives.

2. AEPCO has developed its Construction Work Plan for 2015-2017 (the "CWP"). The CWP identifies necessary improvements, upgrades and replacements to AEPCO's generation plant that are anticipated to be needed over the next several years. Attached hereto as Exhibit A is a schedule providing additional detail regarding the facilities in the CWP that are included in this finance request, which is also referred to as the T-8 loan. As Exhibit A indicates, the estimated total cost of the facilities at issue is $31,167,500.

3. By this Application, AEPCO seeks Commission approval to secure long-term financing in an amount not to exceed $31,167,500 from the Rural Utilities Service/Federal Financing Bank long-term loan program.[1]

4. The Cooperative also requests that the Commission again authorize AEPCO to change the specific facilities to be financed without the necessity of filing an Amended Application so long as the total amount financed does not exceed $31,167,500.

5. In Decision Nos. 71111 and 73728 (which authorized financing for AEPCO's 2009-2011 CWP and 2012-2014 CWP, respectively), the Commission approved such a process. It allows AEPCO to modify facilities within the CWP by filing proposed changes with Docket Control. Unless Staff objects to the filing within sixty days, the revisions are deemed approved without the need to file an amended application. AEPCO used the procedure in March 2011 and it worked well. It saved the Cooperative, the Utilities Division Staff, the Hearing Division, and the Commission the time and resources associated with a formal amendment process, but still afforded Staff a review opportunity of the revised projects proposed for funding. Additionally, AEPCO recently filed a proposed modification to its 2012-2014 CWP (pursuant to the Commission's authorization in Decision No. 73728) and anticipates that the process will work well again.[2] Accordingly, AEPCO asks that this same procedure be approved in connection with the current financing application.

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[1] The Cooperative is not requesting approval for interim financing because, pursuant to the Commission's authorization in Decision No. 74447, AEPCO has in place two unsecured, committed revolving lines of credit that are sufficient to provide interim funding.

[2] AEPCO filed its Notice of Proposed Modification in Docket No. E-01773A-12-0192 on September 24, 2015. The filing identifies several projects to be financed through unused, available funds under the Cooperative's S-8 Loan, which was authorized in Decision No. 73728. Included in the list are certain projects from AEPCO's 2015-2017 CWP. Because it is anticipated that AEPCO's modification will be deemed approved on November 23, 2015, the projects identified for realignment with the S-8 Loan are not included in the current T-8 Loan request.

6. In support of the Application, AEPCO provides the following additional requested information:

a. Applicant's Name and Address

Arizona Electric Power Cooperative, Inc.
Attention: Gary Pierson, Manager of Financial Services
P.O. Box 670
1000 S. Highway 80
Benson, AZ 85602
Telephone: 520-586-5364
E-mail: gpierson@ssw.coop

b. Person Authorized to Receive Communications

Jennifer Cranston
Gallagher & Kennedy, P.A.
2575 E. Camelback Road
Phoenix, AZ 85016
Telephone: 602-530-8191
E-mail: jennifer.cranston@gknet.com

c. Responses to Standard Initial Financing Data Requests

AEPCO's Responses (excluding attachments) are attached hereto as Exhibit B. Simultaneous with this filing, three sets of AEPCO's Responses (including attachments) are being submitted to Docket Control as supporting documentation. Please note that some of the data requests seek confidential information, which will be provided to Staff upon execution and return of a protective agreement.

d. A.R.S. § 40-302(A) Factors

AEPCO certifies that the proposed financing meets all the requirements set forth in A.R.S. § 40-302(A): (1) it is within the corporate powers of the Cooperative; (2) it is compatible with the public interest; (3) it is compatible with sound financial practices; (4) it is compatible with the proper performance of AEPCO's service as a public service corporation and will not impair the Cooperative's ability to perform that service; and (5) it will be used to fund improvements, upgrades and replacements to AEPCO's generation plant and, as such, is not reasonably chargeable to operative expenses or to income.

e. Service Fees

There are no service fees.

f. Documents to be Executed

AEPCO's financing application is currently pending before the Rural Utilities Service/Federal Financing Bank. Therefore, there are no documents available at this time.

g. Public Notice

Within ten days of this filing, AEPCO will publish notice of the Application in the *Arizona Daily Star* and *The Kingman Daily Miner*, which are newspapers of general circulation in AEPCO's service area. AEPCO will file the appropriate affidavits of publication within thirty days of this Application.

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

A. Authorizing AEPCO to secure a long-term loan from the Rural Utilities Service/Federal Financing Bank guaranteed loan program to finance its 2015-2017 CWP in an amount not to exceed $31,167,500;

B. Authorizing AEPCO to file in this docket any proposed modifications to the CWP which substantially conform to the purposes of the CWP, but do not exceed the authorized amount of $31,167,500, and unless Staff files an objection to the proposed modifications within 60 days of AEPCO filing the proposed changes, the proposed modifications shall be deemed approved;

C. Authorizing AEPCO to grant liens in its property as required in order to secure the borrowings authorized; and

D. Authorizing AEPCO to engage in any transactions and to execute any documents necessary to effectuate the authorizations granted.

RESPECTFULLY SUBMITTED this 13th day of November, 2015.

GALLAGHER & KENNEDY, P.A.

By ______________________
Jennifer A. Cranston
2575 East Camelback Road
Phoenix, Arizona 85016-9225
Attorneys for Arizona Electric Power Cooperative, Inc.

Original and 13 copies filed this
13th day of November, 2015, with:

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

____

5118695v2/10421-0075

EXHIBIT A

Arizona Electric Power Cooperative, Inc. **Exhibit A**

AZ 028 T8 Apache

(2015 - 2017 Construction Work Plan, Am. #0)

RUS Code	Project Name	Project Number	2015 CWP Year 1	2016 CWP Year 2	2017 CWP Year 3	Estimate	revision number
1200.14	ST2 Mercury Control	5-01308	$1,300,000.00	$0.00	$0.00	$1,300,000.00	0 - Original
1200.17	ST3 SDAS Bypass Duct Upgrade	5-01324	$1,100,000.00	$0.00	$0.00	$1,100,000.00	0 - Original
1200.18	ST1 Low NOx Burners	5-01242	$0.00	$2,500,000.00	$0.00	$2,500,000.00	0 - Original
1200.19	RO Sump Investigation	5-01272	$0.00	$100,000.00	$0.00	$100,000.00	0 - Original
1200.20	ST2 Nitrogen Blanket System Install	5-01302	$0.00	$136,000.00	$0.00	$136,000.00	0 - Original
1200.21	Miscellaneous Cable Replacement	5-01305	$0.00	$114,000.00	$0.00	$114,000.00	0 - Original
~~1200.22~~	~~GT2 Controls Upgrade 2016~~	5-01306	$0.00	$350,000.00	$0.00	$350,000.00	0 - Original
1200.23	Grinnell Fire System Upgrades	5-01307	$0.00	$60,000.00	$0.00	$60,000.00	0 - Original
1200.24	GT4 Stage 1 HPC Replacement	5-01210	$0.00	$128,000.00	$0.00	$128,000.00	0 - Original
1200.25	ST2 .085 NOx Compliance Upgrades	5-01275	$0.00	$0.00	$7,000,000.00	$7,000,000.00	0 - Original
1200.26	ST3 Classifier Replacement	5-00921	$0.00	$0.00	$1,345,000.00	$1,345,000.00	0 - Original
1200.27	ST3 Condenser Air Removal Re-tube	5-01170	$0.00	$0.00	$491,000.00	$491,000.00	0 - Original
1200.28	ST3 Yokogawa Replacement	5-01220	$0.00	$0.00	$67,500.00	$67,500.00	0 - Original
1200.29	ST3 SDAS Mist Eliminator Upgrade	5-01229	$0.00	$0.00	$400,000.00	$400,000.00	0 - Original
1200.30	ST3 Generator Auto Voltage Regulator Upgrade	5-01241	$0.00	$0.00	$430,000.00	$430,000.00	0 - Original
1200.31	ST1 Main Step-Up XFMR Bushing Replace	5-01243	$0.00	$0.00	$112,000.00	$112,000.00	0 - Original
1200.32	ST3 NOx Reduction Upgrades	5-01283	$0.00	$0.00	$9,970,000.00	$9,970,000.00	0 - Original
1200.33	ST3 SDAS Towers Outlet Upgrade	5-01315	$0.00	$0.00	$1,144,000.00	$1,144,000.00	0 - Original
1200.34	ST3 Turbine Blades Replace	5-01313	$0.00	$0.00	$163,000.00	$163,000.00	0 - Original
1200.35	ST3 Turbine Valve Stem Upgrade	5-01314	$0.00	$0.00	$114,000.00	$114,000.00	0 - Original
1200.36	ST3 ID Fans Speed Changer Circuit Upgrade	5-01316	$0.00	$0.00	$39,000.00	$39,000.00	0 - Original
1200.37	ST3 SNCR Installation	5-01317	$0.00	$0.00	$3,661,000.00	$3,661,000.00	0 - Original
1200.38	ST3 Boilier Splash Screen Upgrade	5-01312	$0.00	$0.00	$155,000.00	$155,000.00	0 - Original
1200.39	ST3 HP Feed Waters Heater Level Control	5-01135			$96,000.00	$96,000.00	0 - Original
1200.96	ST3A Replace Mill Throat Liners	5-00852	$0.00	$0.00	$192,000.00	$192,000.00	0 - Original
Annual Subtotal for T-8 Loan			$2,400,000.00	$3,388,000.00	$25,379,500.00	$31,167,500.00	

EXHIBIT B

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.1 Provide audited financial statements for the Company's most recent fiscal year end to include, but not limited to, balance sheets, income statements, reconciliation of retained earnings (membership capital or equity), cash flow statements, footnotes, disclosures, and any other pertinent documentation including a schedule of general and administrative costs, and all management and accountants opinion letters. Un-audited financial statements will suffice if audited statements are not routinely generated. If the financial statements provided are not for the fiscal year immediately preceding the calendar year in which the current financing approval application is docketed, indicate when the more recent financial statements are expected to be available and provide them as soon as they become available.

Response: See the attached audited financial statement for the calendar year ended December 31, 2014.

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015**

1.2 Provide the name and address of the lender or debt placement agent, and the expected terms of the planned financing, including but not limited to, loan amount, inception date, maturity date, interest rate (for variable interest rates state the basis upon which the rate is dependent and the time interval or frequency the changes are implemented), numerical covenants such as debt service coverage ("DSC"), times interest earned coverage ("TIER"), cash coverage ratio ("CCR"), equity-to-total capital ratio, etc. For amortizing loans, provide an amortization schedule showing the scheduled payments for principal and interest for the full duration of the loan.

Response: AEPCO has applied for financing not to exceed $31,167,500 from the Federal Financing Bank ("FFB") through the United States Department of Agriculture, Rural Utilities Service ("RUS") under the terms of AEPCO's existing mortgage dated August 3, 2009 and any subsequent supplemental mortgage agreements. Parties to the mortgage include AEPCO as debtor, RUS and the National Rural Utilities Cooperative Finance Corporation ("CFC") as mortgagees. The mortgagee addresses are:

Rural Utilities Service
United Stated Department of Agriculture
1400 Independence Ave., SW
Washington, DC 20250-1500

and

National Rural Utilities Cooperative Finance Corporation
20701 Cooperative Way
Dulles, VA 20166

The inception date will be determined when approval of the loan application is received from the RUS. The final maturity date is expected to be December 31, 2034. Each advance shall have its own amortization schedule from issuance to final maturity. The interest rate of each individual loan advance will be determined at the time the advance is made based on treasury rates then in effect. Under the current mortgage, AEPCO is required to maintain a TIER of 1.05 and DSC of 1.0 in the highest two of the three most recent fiscal years. Once the current mortgage is replaced by an indenture (as approved by the Commission in Decision No. 74591), these covenants will be replaced with similar Margins for Interest and DSC requirements.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.3 Provide an explanation of the proposed use of the financing proceeds. If the proceeds of the financing are for funding multiple projects/uses or a construction work plan ("CWP"), provide a detailed list of the projects/uses or a copy of the CWP and the associated cost and the expected funding dates for each. Also provide a copy of any independent external engineering review of the CWP.

Response: AEPCO plans to use the proceeds of this financing to fund certain projects identified in AEPCO's Construction Work Plan 2015-2017. A list of the specific projects included in AEPCO's financing request is attached to the Application as Exhibit A. A copy of the complete work plan is attached to this response. Loan funding will be advanced under this loan package as each project is placed in service.

Please note that some of the projects identified in the attached plan are not listed in Exhibit A to the Application. This is because certain projects in the 2015-2017 plan have been submitted for realignment to AEPCO's S-8 loan, which was initially approved in Decision No. 73728 in Docket No. E-01773A-12-0192. *See* AEPCO's Notice of Proposed Modifications, dated September 24, 2015, attached. If no Staff objection is filed by November 23, 2015, those projects will be deemed approved for funding through the S-8 loan such that they have not been included in the current T-8 loan request.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.4 If interim funding is to be utilized for the projects in the CWP, identify the source of all elements of this expected interim funding and when the interim funding is expected to be retired and replaced with permanent funding from this new financing arrangement.

Response: Pursuant to the Commission's authorization in Decision No. 74447 in Docket No. E-01773A-14-0019, AEPCO has two unsecured, committed revolving lines of credit sufficient to provide interim funding. AEPCO will draw down the funds from the permanent financing that is the subject of its current application to repay the lines of credit as each project is placed in service.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.5 Provide the balances, if any, of "Advances in Aid of Construction" and "Contributions in Aid of Construction," as of the end of the Company's most recent fiscal year.

Response: AEPCO received a grant in 2014 through RUS's Rural Energy for America Program for a solar covered parking facility in the amount of $39,619. Additional funding for this project is being provided by one of AEPCO's Class A member distribution cooperatives (Sulphur Springs Valley Electric Cooperative) as a performance-based incentive. Total funding provided for this project is $49,810.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.6 Provide proof of notice of this matter duly published within newspapers of general circulation within the Company's service territory, as specified in the finance application form at http://www.azcc.gov/divisions/utilities/forms.asp. Identify any other method (e.g., direct mail) used to provide customer notice of the financing application, provide a copy of the notice and specify the date the notice was provided to customers and provide an affidavit attesting to the provision of the supplemental or alternate notice method.

Response: Within ten days of the filing of its application, AEPCO will publish notice of the application in the *Arizona Daily Star* and *The Kingman Daily Miner*, which are newspapers of general circulation in AEPCO's service area. AEPCO will file the appropriate affidavits of publication within thirty days of filing its application.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.7 Provide the number of customers currently served by rate class, and a brief description of each class of customers (residential, commercial, etc.).

Response: See the attached schedule summarizing AEPCO's Class A Members' Form 7 data for 2014.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.8 Provide a schedule detailing all financing approvals obtained by the Arizona Corporation Commission ("Commission") that remain in effect and indicate docket numbers, amounts approved, amounts drawn and any balances not yet drawn. For any balances not yet drawn, provide an explanation of why the funds have not been drawn and how the Company intends to utilize this currently available borrowing capacity.

Response: AEPCO has two financing approvals in effect.

Decision No. 73728 in Docket No, E-01773A-12-0192 approved permanent financing not to exceed $32,042,700 and interim financing not to exceed $38,907,400. As of October 31, 2015, AEPCO had drawn $13,000,000 under the permanent financing facility. AEPCO expects to utilize the full amount approved to finance the projects identified in its 2012-2014 CWP, as modified by the September 24, 2015 Notice of Proposed Modifications, attached to AEPCO's response to data request 1.3.

Decision No. 74447 in Docket No. E-01773A-14-0019 approved two unsecured, committed revolving lines of credit not to exceed the combined amount of $100,000,000. As of October 31, 2015, $5,000,000 had been drawn. AEPCO expects to pay-off and re-draw funds as needed for interim financing.

1.9 If not clearly identified with the financial statements and footnotes of the financial statements provided in response to 1.1, provide a complete list of all long-term debt obligations (including capital leases). For each obligation provide: the lender's name and contact information, the initial loan amount, the current outstanding (unpaid) balance, the inception date, the maturity date(s), the annual interest rate (for variable interest rates state the basis upon which the rate is dependent and the time interval or frequency the changes are implemented), the numerical covenants such as DSC, TIER, CCR, equity-to-total capital ratio, etc. For amortizing loans, provide an amortization schedule showing the scheduled payments for principal and interest. Also, provide any other information pertinent for gaining an essential understanding of the Company's debt obligations.

Response: See the attached schedules detailing the requested information regarding loan amounts, outstanding balances, inception and maturity dates, and interest rates. Lender contact information and numerical covenants are provided in AEPCO's response to data request 1.2.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.10 If any of the proceeds from the newly proposed debt will be used to retire existing long-term or short-term debt, identify the specific loans, amounts and anticipated dates for the refunding.

Response: AEPCO does not expect to use any of the proceeds from the proposed debt to retire existing long-term debt. Proceeds may be used to pay down any amounts used under the revolving lines of credit to fund projects identified in this application.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.11 Provide a certificate of resolution from the board of directors authorizing the filing of this application.

Response: A copy of the AEPCO Board resolution is attached.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.12 Provide financial information projecting the Company's estimated financial performance (cash flows, operating income) for each of the next five years, identifying all significant assumptions (e.g., rate increases, customer/sales grow, inflation, etc.).

Response: AEPCO's Long Range Financial Forecast contains confidential material. Accordingly, a copy of the forecast will be provided to Staff upon execution and return of a protective agreement.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.13 If the Company has a revolving line-of-credit facility ("LOC"), provide the following: the execution date, the termination date, the maximum borrowing capacity, the balance for each of the most recent 12 months, the name of the lender, the basis and term for the interest rate charged (e.g., LIBOR plus 2.0 percent), a detailed explanation of any fees other than interest (e.g., a commitment fee) and an explanation of any changes the Company anticipates to the line-of-credit during the next five years.

Response: AEPCO maintains two unsecured, committed revolving line of credit facilities in the amount of $50,000,000 with the CFC and $50,000,000 with CoBank. The CFC facility was executed on June 5, 2014 and has a term of five years with two possible one-year extensions. The CoBank line was executed August 21, 2014 and has a term of five years. This financing was approved in Decision No. 74447 in Docket No. E-01773A-14-0019.

Balance information is provided on the attached schedule. AEPCO intends to continue to use these facilities as liquidity support as well as interim financing. Within the next five years, AEPCO may exercise the CFC extensions (as authorized by the Commission in Decision No. 74447) and may seek to renew the CoBank LOC.

The contact information for CFC is provided in AEPCO's response to data request 1.2. The contact information for CoBank is:

CoBank, ACB
5500 South Quebec St.
Greenwood Village, CO 80111

The remaining requested information is deemed confidential. Accordingly, AEPCO will provide the additional information to Staff upon execution and return of a protective agreement.

**ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015**

1.14 If applicable, provide the Company's most recent credit agency(ies) financial review(s).

Response: AEPCO does not have a public credit rating at this time.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.15 Provide the Commission decision number and date for the Company's most recent general rate case and state the date of the test year end used in that rate case.

Response: AEPCO's most recent general rate case decision, Decision No. 74173, was issued on October 25, 2013. The test year was the calendar year ended December 31, 2011.

1.16 Identify any additional financing authorizations the Company contemplates seeking from the Commission in the next five years.

Response: AEPCO may file additional financing applications as new CWPs are developed for future periods.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.17 For a financing application by an electric provider in which the funds will be used for projects in a CWP that has not been previously reviewed by the Commission, provide the following information in the spreadsheet provided:

a. Peak Demand (MW) & Energy MWh for the most recent previous five years.
b. Peak Demand (MW) & Energy (MWh) projected for the next five years.
c. Historical System Losses in MWh for the most recent previous five years.
d. Number of Customers for the most recent previous five years by Customer Class.
e. Total System Average Interruption Duration Index (SAIDI) for the most recent previous five years as well as SAIDI by the causes of Power Supplier, Planned, Major Events, and All Other.

Response: See the attached spreadsheets. Please note the customer numbers were derived from AEPCO's Class A Members' Form 7 data.

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR AUTHORIZATION TO INCUR DEBT AND SECURE LIENS IN ITS PROPERTY TO FINANCE ITS CONSTRUCTION WORK PLAN	Docket No. E-01773A-15-0389 **APPLICATION**

SUPPORTING DOCUMENTATION

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.1 Provide audited financial statements for the Company's most recent fiscal year end to include, but not limited to, balance sheets, income statements, reconciliation of retained earnings (membership capital or equity), cash flow statements, footnotes, disclosures, and any other pertinent documentation including a schedule of general and administrative costs, and all management and accountants opinion letters. Un-audited financial statements will suffice if audited statements are not routinely generated. If the financial statements provided are not for the fiscal year immediately preceding the calendar year in which the current financing approval application is docketed, indicate when the more recent financial statements are expected to be available and provide them as soon as they become available.

Response: See the attached audited financial statement for the calendar year ended December 31, 2014.

Report of Independent Auditors
and Financial Statements for

Arizona Electric Power Cooperative, Inc.

December 31, 2014 and 2013

MOSS-ADAMS LLP

Certified Public Accountants | Business Consultants

CONTENTS

MOSS-ADAMS LLP
Certified Public Accountants | Business Consultants

REPORT OF INDEPENDENT AUDITORS

To the Board of Directors
Arizona Electric Power Cooperative, Inc.

Report on the Financial Statements

We have audited the accompanying financial statements of Arizona Electric Power Cooperative, Inc. (the Cooperative), which comprise the balance sheets as of December 31, 2014 and 2013, and the related statements of revenues and expenses and unallocated accumulated margins, and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Cooperative's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Cooperative's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

REPORT OF INDEPENDENT AUDITORS (continued)

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinions

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Arizona Electric Power Cooperative, Inc. as of December 31, 2014 and 2013, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated April 1, 2015 on our consideration of the Cooperative's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the Cooperative's internal control over financial reporting and compliance.

Moss Adams LLP

Portland, Oregon
April 1, 2015

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ARIZONA ELECTRIC POWER COOPERATIVE, INC.
BALANCE SHEETS

ASSETS

	December 31, 2014	December 31, 2013
UTILITY PLANT		
Plant in service	$ 480,004,178	$ 477,034,644
Construction work in progress	1,442,661	2,557,721
Total utility plant	481,446,839	479,592,365
Less accumulated depreciation	237,458,915	229,817,382
Utility plant, net	243,987,924	249,774,983
INVESTMENTS		
Restricted	8,257,153	8,716,929
Unrestricted	10,925,361	9,860,534
Total investments	19,182,514	18,577,463
CURRENT ASSETS		
Cash and cash equivalents		
General unrestricted	20,911,043	25,014,134
Restricted	538,841	812,749
Accounts receivable	19,077,701	22,112,313
Inventories, at average cost		
Coal and natural gas	6,227,522	9,749,528
Materials and supplies	8,965,860	8,452,955
Prepayments and other current assets	1,631,063	1,072,605
Notes receivable	254,068	289,897
Total current assets	57,606,098	67,504,181
DEFERRED DEBITS	11,929,435	10,547,196
Total assets	$ 332,705,971	$ 346,403,823

See accompanying notes.

MEMBERSHIP CAPITAL AND LIABILITIES

	December 31, 2014	December 31, 2013
MEMBERSHIP CAPITAL		
Membership fees	$ 430	$ 430
Patronage capital	110,575,235	99,754,863
Unallocated accumulated margins	6,265,177	11,541,730
Total membership capital	116,840,842	111,297,023
LONG-TERM DEBT		
Federal Financing Bank	150,859,361	154,324,052
Advance payments unapplied	(14,796,645)	(10,312,800)
Solid Waste Disposal Revenue bonds	10,383,122	11,259,620
Cooperative Finance Corporation	13,387,017	16,717,512
Capital lease obligation	211,763	63,026
Total long-term debt	160,044,618	172,051,410
CURRENT LIABILITIES		
Member advances and other investments	5,729,731	7,887,583
Current maturities of capital lease obligation	59,525	148,245
Current maturities of long-term debt	10,905,568	10,440,555
Accounts payable	9,593,858	14,542,637
Accrued property and business taxes	1,711,576	1,345,294
Accrued interest	21,073	35,501
Accumulated over-recovered fuel and purchase power costs	1,847,441	2,613,216
Other	126,585	159,986
Total current liabilities	29,995,357	37,173,017
DEFERRED CREDITS AND OTHER LIABILITIES	25,825,154	25,882,373
Total membership capital and liabilities	$ 332,705,971	$ 346,403,823

See accompanying notes.

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

	Years Ended December 31, 2014	2013
OPERATING REVENUES		
Sales of electric energy		
Members		
Class A – Firm	$ 162,815,800	$ 157,718,440
Class D	599,305	163,947
(Over) under-recovery of fuel and purchase power costs	(7,813,226)	(1,762,807)
Nonmembers	17,863,496	8,221,185
Other, net	7,594,891	5,651,360
Total operating revenues	181,060,266	169,992,125
OPERATING EXPENSES		
Power generation		
Fuel	77,551,942	73,249,174
Operation	10,766,623	11,667,608
Maintenance	13,513,147	15,134,158
Purchased power and interchange	26,327,417	18,387,869
Administration and general	8,724,450	9,543,230
Depreciation, amortization, and accretion	13,073,564	10,344,701
Transmission	15,068,170	10,903,833
Property and other taxes	3,222,381	2,645,207
Total operating expenses	168,247,694	151,875,780
OPERATING MARGIN	12,812,572	18,116,345
Interest and interest related expenses, net	(8,613,178)	(9,026,149)
Other, net	2,065,783	2,451,534
NET MARGIN	6,265,177	11,541,730
UNALLOCATED ACCUMULATED MARGINS, beginning of year	11,541,730	4,966,108
PATRONAGE CAPITAL ALLOCATION	(11,541,730)	(4,966,108)
UNALLOCATED ACCUMULATED MARGINS, end of year	$ 6,265,177	$ 11,541,730

See accompanying notes.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Net margin	$ 6,265,177	$ 11,541,730
Adjustments to reconcile net margin to net cash from operating activities		
Depreciation and amortization	13,073,564	10,344,701
Amortization of deferred charges	76,823	55,145
Patronage capital allocations	(1,114,540)	(1,881,160)
Changes in assets and liabilities		
Accounts and notes receivable	3,070,441	(8,614,359)
Inventories	3,009,101	9,072,369
Prepayments and other current assets	(558,458)	804,354
Deferred debits	(1,459,062)	3,489,036
Accounts payable	(4,948,779)	4,406,038
Accrued interest	(14,428)	393
Deferred credits	(800,652)	108,894
Accumulated over-recovered fuel and purchased power costs	(765,775)	120,004
Accrued property and business taxes and other	332,881	(362,900)
Net cash from operating activities	16,166,293	29,084,245
CASH FLOWS FROM INVESTING ACTIVITIES		
Construction expenditures, net	(6,543,072)	(3,712,322)
Purchases and redemptions of investments, net	509,489	508,280
Net cash from investing activities	(6,033,583)	(3,204,042)
CASH FLOWS FROM FINANCING ACTIVITIES		
Retirement of patronage capital credits	(721,358)	(620,764)
Member advances and other investments, net	(2,157,852)	2,274,409
Proceeds from long-term debt	4,000,000	6,098,702
Advance payments	(4,752,044)	(670,548)
Payments on long-term debt and capital lease obligation	(10,878,455)	(11,062,511)
Net cash from financing activities	(14,509,709)	(3,980,712)
CHANGE IN CASH AND CASH EQUIVALENTS	$ (4,376,999)	$ 21,899,491
CASH AND CASH EQUIVALENTS, beginning of year	25,826,883	3,927,392
CASH AND CASH EQUIVALENTS, end of year	$ 21,449,884	$ 25,826,883

See accompanying notes.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2014	2013
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Cash paid for interest, net of amount capitalized	$ 8,550,783	$ 8,970,611
Noncash investing activities		
Liabilities incurred for asset retirement obligations	$ -	$ 13,447,660
Assets acquired under a capital lease	$ -	$ 89,280

See accompanying notes.

Note 1 - Organization

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

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

Note 2 - Summary of Significant Accounting Policies

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

Accounting for the effects of regulation - Due to the regulation of its rates by the ACC, the Cooperative prepares its financial statements in accordance with Regulated Operations. This accounting requires a cost-based, regulated enterprise to recognize revenues and expenses in the time periods when the revenues and expenses are included in rates. This may result in regulatory assets and liabilities until such time that the related revenues and expenses are included in rates.

Utility plant - Utility plant, consisting primarily of coal and natural gas electric generation facilities, is stated at historical cost and includes the costs of outside contractors, direct labor and materials, allocable overhead and interest charged during construction.

In accordance with the Uniform System of Accounts, the Cooperative capitalizes the interest costs associated with the borrowing of funds used to finance construction work in progress (CWIP). Interest income from construction funds held in trust, if any, is credited to CWIP. Interest costs capitalized on construction projects was approximately $12,000 and $7,000 for 2014 and 2013, respectively.

Depreciation is computed on the straight-line basis over estimated useful lives of depreciable property in accordance with rates prescribed by RUS, averaging 2.58% and 2.14% in 2014 and 2013, respectively. Minor replacements and repairs are charged to expense as incurred. When utility plant is retired, sold, or otherwise disposed of, the original cost plus the cost of removal less salvage value is charged to accumulated depreciation, along with any corresponding gain or loss.

Note 2 – Summary of Significant Accounting Policies (continued)

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

Asset retirement obligations – Accounting standards require the recognition of an Asset Retirement Obligation (ARO), measured at estimated fair value, for legal obligations related to decommissioning and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. The initial capitalized asset retirement costs are depreciated over the life of the related asset, with accretion of the ARO liability classified as an operating expense (see Note 10 – *Asset retirement obligation*).

Investments – The Cooperative accounts for its investments in accordance with accounting for certain investments in debt and equity securities. At December 31, 2014 and 2013, all investment balances are recorded at amortized cost which approximates fair market value (see Note 3).

A decline in the market value of securities below cost that is deemed to be other-than-temporary results in a reduction in carrying amount to fair value. The impairment is charged to margins and a new cost basis for the security is established. To determine whether an impairment is other-than-temporary, the Cooperative considers whether it has the ability and intent to hold the investment until a market price recovery and considers whether evidence indicating the cost of the investment is recoverable outweighs evidence to the contrary. Evidence considered in this assessment includes the reasons for the impairment, the severity and duration of the impairment, changes in value subsequent to year end and forecasted performance of the investee. Management does not believe the investments are impaired as of December 31, 2014 and 2013.

Cash equivalents – The Cooperative considers all investments with an original maturity of 90 days or less to be cash equivalents. The Cooperative maintains its cash in bank accounts, which, at times, exceed federally insured limits and has not experienced any losses in such accounts. Restricted cash consists of special deposits and economic development funds which are restricted in use.

Receivables – Receivables are recorded when invoices are issued and are written off when they are determined to be uncollectible. The allowance for doubtful accounts is estimated based on historical losses, review of specific problem accounts, the existing economic conditions in the industry and the financial stability of customers. Generally, accounts receivable are considered past due after 30 days. No allowance was deemed necessary at December 31, 2014 and 2013.

Note 2 – Summary of Significant Accounting Policies (continued)

Solar Grant – The Cooperative submitted an application to the United States Department of Agriculture (USDA) for a Renewable Energy System grant under the Rural Energy for America Program. USDA approved the grant application in the amount of $39,619 to partially fund the installation of a 27 kW photovoltaic solar system. The project start date for this grant was July 1, 2013 with project implementation not to exceed twenty-four months. The project was completed January 27, 2014. (See Note 11 – *Capital Lease*).

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

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

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

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

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

In its October 25, 2013 rate order, the ACC approved a new purchased power and fuel cost adjustor (the adjustor) for the Cooperative and approved a tariff rider to refund the over-collected balances as of October 31, 2013, for the previous adjustor. The tariff rider refunded the over-collected balances for the previous adjustor by the end of November 2014. Starting on November 1, 2013, the new adjustor enables the Cooperative to accumulate it's over and under collection of fuel and purchased power costs and subsequently, as approved by the ACC, refund or collect from its members the amount of over and under collection of fuel and purchased power costs. Such amounts are recorded as revenue in the period the costs are incurred. On October 31, 2014, the Cooperative filed an application to refund STB Reparations over a twenty-four month period (see Note 10). The application was approved by the ACC and the tariff rider went into effect on January 1, 2015.

Fair value of financial instruments – Many of the Cooperative's financial instruments lack an available trading market as characterized by a willing buyer and willing seller engaged in an exchange transaction (Level 3). As a result, significant estimations using the best available information and present value calculations are used by the Cooperative for purpose of disclosure. For current financial instruments, the carrying amounts approximate fair value.

Note 2 – Summary of Significant Accounting Policies (continued)

Use of estimates – The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include the adjustor, depreciation, asset retirement obligation and overhaul amortization. Actual results could differ from these estimates.

Subsequent events – Accounting standards require disclosure of the date through which subsequent events have been evaluated, as well as whether the date is the date the financial statements were issued or the date the financial statements were available to be issued. The Cooperative has evaluated subsequent events through April 1, 2015, the date the financial statements were available to be issued.

Reclassifications – Certain reclassifications have been made to the prior-year balances to conform with the current-year presentation. These reclassifications did not affect previously reported net margins.

Note 3 – Investments

Investments at December 31 consist of the following:

	2014		
	Amortized Cost	Unrealized Loss	Fair Value
Restricted – municipal bonds	$ 3,018,701	$ (18,251)	$ 3,000,450
Restricted – term certificates	5,238,452	-	5,238,452
Investment in associated organizations	1,244,642	-	1,244,642
Patronage capital	9,680,719	-	9,680,719
Total	$ 19,182,514	$ (18,251)	$ 19,164,263

	2013		
	Amortized Cost	Unrealized Gain	Fair Value
Restricted – municipal bonds	$ 2,951,796	$ 129,903	$ 3,081,699
Restricted – term certificates	5,765,133	-	5,765,133
Investment in associated organizations	1,233,200	-	1,233,200
Patronage capital	8,627,334	-	8,627,334
Total	$ 18,577,463	$ 129,903	$ 18,707,366

Note 3 – Investments (continued)

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

	2014		2013	
	Cost	Fair Value	Cost	Fair Value
Due from one year to five years	$ 3,292,075	$ 3,273,825	$ 3,731,337	$ 3,804,964
Due from six years to ten years	1,668,560	1,668,560	1,656,074	1,712,351
Due after ten years	3,296,518	3,296,517	3,329,518	3,329,517

Municipal bonds – As a condition of National Rural Utilities Cooperative Finance Corporation's (CFC) guarantee of the Solid Waste Disposal Revenue Bonds (see Note 8), the Cooperative purchased a non-interest bearing Debt Service Reserve Certificate (the certificate) maturing in 2024 upon final payment of the debt. The proceeds of the certificate are held by CFC in a Debt Service Reserve Fund (DSRF). At December 31, 2013, the investments included four municipal bonds for approximately $543,000, $417,000, $1,113,000 and $827,000, which bore interest at 3.43%, 3.35%, 3.53% and 3.45% per annum, respectively. On November 15, 2014 all four bonds were called resulting in a net gain of $85,691. Two new bonds were purchased on December 1, 2014. At December 31, 2014, the investments included two municipal bonds for approximately $2,042,000 and $923,000, which bear interest at 2.37% and 2.21% per annum, respectively.

Municipal bonds are valued based on quoted market prices for those or similar investments.

Term certificates – The Cooperative is a member of CFC, a not-for-profit cooperative financing institution. As a condition of membership, the Cooperative purchased Subscription Capital Term Certificates (SCTCs). The SCTCs, totaling $2,759,517 at December 31, 2014 and 2013, bear interest at 5.00% per annum and have maturity dates ranging from 2070 to 2080.

As a condition of the Solid Waste Disposal Revenue Bonds (see Note 8), which are guaranteed by CFC, the Cooperative purchased a Subordinated Term Certificate (STC). The STC, totaling $537,000 and $570,000 at December 31, 2014 and 2013, respectively, bears interest at 7.57% per annum and matures in full in 2024 upon final payment of the related debt.

As a condition of the long-term debt due CFC (see Note 8), the Cooperative purchased Zero Term Certificates (ZTCs). ZTCs totaling $2,435,616 purchased in 2011 bear interest at 3.04% per annum and have maturity dates ranging from 2015 to 2018.

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

Note 3 – Investments (continued)

Investment in associated organizations – The Cooperative is a member of Sierra Southwest Cooperative Services, Inc. (Sierra). The Cooperative's investment in Sierra was $36,000 as of December 31, 2014 and 2013 and is carried at cost (see Note 17).

The Cooperative is an equity member of Alliance for Cooperative Energy Services Power Marketing LLC (ACES). The Cooperative's investment in ACES was $961,610 as of December 31, 2014 and 2013 and is accounted for under the cost method of accounting.

In November 2011, the Cooperative invested $195,000 in the capital of Grand Canyon State Electric Cooperative Association (GCSECA). The Cooperative's investment in GCSECA is accounted for under the cost method of accounting.

The Cooperative is a member of CoBank AFB (CoBank). The membership fee is $1,000 and is carried at cost.

The Cooperative is a member of CFC. The membership fee is $1,000 and is carried at cost.

Patronage capital – Patronage capital represents capital credit allocation of margins due to the Cooperative. Such amounts are returned to the Cooperative in accordance with the associated organization's bylaws and/or at their discretion. Of this balance, $8.8 million and $7.8 million represents patronage allocations from Southwest Transmission Cooperative, Inc. (SWTC) as of December 31, 2014 and 2013, respectively (see Note 17).

Note 4 – Restricted Cash and Cash Equivalents

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

	2014	2013
Rural economic development revolving loan program (see Note 6)	$ 260,158	$ 216,121
Other deposits on account	278,683	596,628
Total restricted cash and cash equivalents	$ 538,841	$ 812,749

Note 5 – Accounts Receivable

Accounts receivable at December 31 consist of the following:

	2014	2013
Member energy sales	$ 11,500,914	$ 14,117,305
Nonmember energy sales	3,399,182	3,240,385
Due from related party	3,120,195	2,970,291
Other	1,057,410	1,784,332
Total accounts receivable	$ 19,077,701	$ 22,112,313

Member energy sales – Member energy sales consist of sales to members under their wholesale power sales contracts (see Note 11 – *Member Power Sales Contracts*) and generally are not collateralized.

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

Note 6 – Notes Receivable

In 1998, the Cooperative was awarded a $400,000 RUS Rural Economic Development Grant. The Cooperative contributed matching funds in the amount of $80,000. In accordance with grant guidelines, initial loans made to qualifying recipients at a zero interest rate were repaid over a ten-year period. The loan repayments were used to establish a revolving loan fund, which in turn, is used for providing loans to foster rural economic development. Loans made from repayments of the initial loans may carry an interest rate. In November 2010 and March 2012, the Cooperative issued loans in the amount of $300,000 and $80,000, respectively, at an interest rate of 3.00%. As of December 31, 2014 and 2013, the Cooperative has $260,158 and $216,121, respectively, of cash and cash equivalents restricted for use in this program (see Note 4).

Note 7 – Deferred Debits

Deferred debits at December 31 consist of the following:

	2014	2013
Deferred overhaul costs	$ 9,024,123	$ 8,224,779
Unamortized debt costs	435,711	220,885
Preliminary survey and investigation and other deferred debits	2,403,070	2,016,856
Redemption premium (see Note 8)	66,531	84,676
Total deferred debits	$ 11,929,435	$ 10,547,196

Note 8 – Long-Term Debt

Federal Financing Bank (FFB) – Long-term debt due to FFB is payable at interest rates based on long-term obligations of the United States Government as determined on the date of advance. Interest rates on existing FFB debt ranged from 1.86% to 9.08% in 2014 and 2013. Quarterly principal and interest installments on these obligations extend through 2035. The obligations are guaranteed by RUS. The Cooperative may prepay all outstanding notes by paying the principal amount plus either 1) the difference between the outstanding principal balance of the loan being refinanced and the present value of the loan discounted at a rate equal to the then current cost of funds to the Department of the Treasury for obligations of comparable maturity; 2) 100% of the amount of interest for one year on the outstanding principal balance of the loan being refinanced multiplied by the ratio of a) number of quarterly payment dates remaining to maturity bears to b) number or quarterly payment dates between year 13 of the loan and the maturity date; or 3) present value of 100% of the amount of interest for one year on the outstanding principal balance of the loan.

Solid Waste Disposal Revenue bonds – Principal on these bonds is due in annual installments through 2024. Interest rates on the bonds are variable and subject to revision semiannually. The interest rate in effect at December 31, 2014 and 2013 was 0.65%. Interest is paid semiannually. These bonds are guaranteed by CFC and are not subject to optional redemption prior to maturity.

Advance payments unapplied – RUS established a Cushion of Credit Payment Program, whereby borrowers may make advance payments on their RUS and FFB notes (Notes). These advance payments earn interest at the rate of 5.00% per annum. The advance payments, plus any accrued interest, can only be used for the payment of principal and interest on the Notes. The Cooperative's participation in the Cushion of Credit Payment Program totaled approximately $14,797,000 and $10,313,000 at December 31, 2014 and 2013, respectively. RUS allows borrowers to report a portion of the cushion of credit account balance as a reduction of the current maturities of RUS long-term debt. Accordingly, the Cooperative records the current year allocation under "Current maturities of long term debt" and the residual balance is recorded as a separate line item entitled "Advance payments unapplied" under long-term debt on the balance sheets.

Note 8 – Long-Term Debt (continued)

Cooperative Finance Corporation – Long-term debt due to CFC is payable at fixed rates ranging from 2.90% to 3.80% and a variable interest rate that is established monthly and effective on the first day of each month. The variable interest rate in effect at December 31, 2014 and 2013 was 2.90%. Quarterly principal and interest payments on these obligations extend through 2018. The variable interest rate on the debt is convertible to a fixed rate. The fixed rate would be equal to the rate of interest offered by CFC at the time of the conversion request. The Cooperative may prepay fixed rate notes in whole or in part, subject to a prepayment premium prescribed by CFC.

Maturities of long-term debt – Maturities of long-term debt for the next five years and thereafter are as follows as of December 31, 2014:

2015	$ 10,905,568
2016	11,298,150
2017	11,902,296
2018	12,188,635
2019	9,905,217
Thereafter	114,538,557
	$ 170,738,423

Under covenants of the Consolidated Mortgage and Security Agreement (Mortgage), dated June 14, 1989, by and among the Cooperative, CFC and the United States of America acting through RUS, and RUS general and preloan policies and procedures, the Cooperative must, among other things, obtain approvals from both RUS and CFC for certain transactions and contracts and design its rates with a view to maintaining, on an annual basis, an average times interest earned ratio of 1.05 and debt service coverage ratio of 1.00 calculated retrospectively using the highest ratios from two of the three most recent years. Management believes these financial covenants have been achieved as of December 31, 2014.

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

The fair value of the Cooperative's long-term debt is estimated by discounting the future cash flows required under the terms of each respective debt agreement by the currently quoted or offered rates for the same or similar issues of debt with similar maturities. The principal amounts of variable rate debt are considered reasonable estimates of their fair value. The fair value of debt at December 31, 2014 and 2013 was $189,914,028 and $192,200,411, respectively.

Note 8 – Long-Term Debt (continued)

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

	2014	2013
Total interest costs and related amortization	$ 8,625,566	$ 9,033,312
Interest capitalized	(12,388)	(7,163)
Total interest expense	$ 8,613,178	$ 9,026,149

Note 9 – Member Advances and Other Investments

Member investment program – The Cooperative offers all members the ability to invest funds with the Cooperative on a short-term basis for periods of up to nine months. The Cooperative had recorded liabilities for notes of $5,113,026 and $6,597,335 at December 31, 2014 and 2013, respectively. The interest rate on these notes averaged .75% and .79% in 2014 and 2013, respectively. Interest expense on these notes was approximately $52,000 and $45,000 for the years ended December 31, 2014 and 2013, respectively.

Prepaid power program – The Cooperative also offers a program for all members whereby the members may make interest-bearing prepayments of their monthly power billings. The prepayment and accrued interest are applied to the members' power billings on the date such billings become due. The Cooperative recorded liabilities for prepayments of $616,705 and $1,279,769 at December 31, 2014 and 2013, respectively. The interest rate on these prepayments averaged .75% and .66% in 2014 and 2013, respectively. Interest expense on these prepayments was approximately $4,500 and $7,000 for the years ended December 31, 2014 and 2013, respectively.

Note 10 – Deferred Credits and Other Liabilities

Deferred credits at December 31 consist of the following:

	2014	2013
Surface Transportation Board reparations	$ 7,814,462	$ 9,245,393
Asset retirement obligation	17,271,519	16,528,086
Regulatory liability - ARO	739,173	108,894
Total deferred credits and other liabilities	$ 25,825,154	$ 25,882,373

Note 10 – Deferred Credits and Other Liabilities (continued)

Surface Transportation Board (STB) reparations – On December 30, 2008, the Cooperative filed a complaint challenging the reasonableness of the joint rates established by BNSF Railway Company and Union Pacific Railroad Company (collectively, the defendants) for unit train coal transportation service (see Note 11 – Rail transportation agreement). As a result of the decision by the STB (Docket Number NOR 42113) regarding this complaint, the defendants were ordered to pay reparations to the Cooperative for past, excessive charges. In May 2012, the defendants paid $9,245,393 to the Cooperative and filed an appeal to the STB's decision. The appeal was settled in favor of the Cooperative on May 23, 2014. Both the AEPCO Board of Directors and the ACC have approved the calculated refund amounts due for the energy cost component charges paid by members and former members during the reparation period. The Cooperative distributed $1,430,931 of allocated reparation funds to former members October 20, 2014. The remaining reparations will be returned to current AEPCO members over a 24-month period beginning January 1, 2015 in the form of a credit on their monthly energy billing invoice.

Asset retirement obligation – The Cooperative completed the ARO calculation for the Apache Station Generation Plant in Cochise, Arizona with the assumption that the assets will be in service through the year 2035. The useful life expectations used in the calculations of the ARO are based on the assumption that operations will continue without deviation from historical trends.

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

	2014	2013
Liability at January 1	$ 16,528,086	$ 2,799,664
Decommission expense recognized	743,433	280,762
Liabilities incurred	-	13,447,660
Liability at December 31	$ 17,271,519	$ 16,528,086

The regulatory liability related to the asset retirement obligation calculation at December 31 consists of the following:

	2014	2013
Liability at January 1	$ 108,894	$ -
Estimated recovery	1,978,704	329,784
Less accretion & depreciation expense	(1,348,425)	(220,890)
Liability at December 31	$ 739,173	$ 108,894

Note 11 – Commitments and Contingencies

Class A Member power sales contracts – *Wholesale power sales contracts* – The Cooperative holds all requirements wholesale power sales contracts with three of its six Class A member cooperatives pursuant to which each Class A member agrees to purchase from the Cooperative all of its electric power requirements. These all requirements power contracts expire December 31, 2035, and will remain in effect thereafter until terminated by either party upon six months notice. Management believes the Cooperative will be able to fulfill its requirements on these long-term contracts.

Class A Member power sales contracts – *Partial requirements wholesale power contracts* – The Cooperative holds partial requirements wholesale power sales contracts, expiring December 31, 2035, with three of its Class A member cooperatives pursuant to which the Class A members have agreed to purchase from the Cooperative electric energy up to and capacity at the member's allocated capacity percentage in the Cooperative's total resources existing at the time of execution of the contract.

Class B and Class C Member power sales contracts – There are no Class B or C member contracts at December 31, 2014.

Class D Member power sales contract – Class D membership requires the member to enter into a service contract for scheduling and trading services for a minimum term of 2 years. The service contract with the Cooperative's Class D member is renewed annually until terminated by either party upon a six months written notice. At December 31, 2014, the Cooperative had one Class D member.

Nonmember power and services sales agreements – The Cooperative holds three nonmember scheduling and trading service agreements that have a six-month termination notice, two scheduling and trading services agreements with 90-day termination notices and a nonmember scheduling and energy trading agreement with an initial term through September 30, 2016, which continues thereafter until terminated by either party upon a two (2) year written notice.

Note 11 – Commitments and Contingencies (continued)

Wholesale power purchase contracts – The Cooperative's current power supply includes the following purchase power agreements:

- Hydroelectric power purchases from Western Area Power Administration (Western), a federal power marketing agency. Under the terms of its Salt Lake City Integrated Project (formerly Colorado River Storage Project) contract, which expires September 30, 2024, the Cooperative can receive up to 2.4 MW during October through March and up to 11.7 MW during April through September for service to its Class A members. Additionally, under the terms of a contract with the Parker Davis Project, which expires September 30, 2028, the Cooperative receives 18.3 MW during October through February and 23.6 MW during March through September.

- Power purchase agreement with Salt River Project up to 15 MW capacity and energy at a maximum of 44% capacity factor per month and priced at less than the market price for Peak Hours with a term to begin in January 2016 and ending 20 years thereafter.

- Power purchase agreement with Sempra Generation to purchase up to 2 MW capacity and energy at a maximum of 100% capacity factor per month with a term to begin in January 1, 2015 and ending December 31, 2039.

Network service agreement (Class A) – The Cooperative holds an agreement with SWTC for network integration transmission service for delivery of its power sales to the Cooperative's all requirements Class A members. This agreement remains in effect as long as any existing wholesale power contract between the Cooperative and any of the all requirements Class A members remains in effect (see Note 17).

Wholesale transmission contracts – The Cooperative holds separate agreements by which it takes transmission services from other entities totaling 205 MW, which will remain in effect in accordance with each respective service agreement. The Cooperative holds transmission service agreements with SWTC for 315 MW, which have no expiration date. The Cooperative uses these agreements to receive power from the wholesale power market as well as to receive or deliver power associated with the Southwest Reserve Sharing Group agreement. In the opinion of management, the Cooperative will be able to continue to use these contracts to provide service to the Class A members in accordance with their agreements.

Rate filing application –On July 5, 2012, the Cooperative filed an application for rate relief requesting new rates to become effective on November 1, 2013 and the continuance of the Cooperative's purchased power and fuel cost adjustor. On October 25, 2013, the ACC issued a decision approving a 2.78% decrease in revenues and authorizing new rate tariffs and a purchased power and fuel adjustment clause, which became effective on November 1, 2013. The ACC also ordered that the record be held open until April 30, 2014 allowing the Cooperative, after collaboration with the ACC Staff, to file an environmental cost adjustment rider and plan of administration.

Note 11 – Commitments and Contingencies (continued)

Additionally, the Cooperative was ordered, as a compliance item, to file an application by no later than August 1, 2014 requesting to remove from its rates all costs and charges related to the two purchase power contracts that expired on October 31, 2014. Further, the ACC authorized the implementation of new depreciation rates effective November 1, 2013. On August 1, 2014, the Cooperative filed an application requesting to remove from its rates all costs and charges related to two purchase power contracts that expired on October 31, 2014. The application was approved by the ACC and the new tariff rates became effective November 1, 2014.

Fuel procurement contracts – ***Coal supply agreements*** – To ensure an adequate fuel supply, the Cooperative enters into various long-term fuel contracts. At December 31, 2014, these contracts consist of:

- A 60-month agreement that includes an amendment adding a 36-month term that is effective January 1, 2015. The terms of the agreement require the Cooperative to purchase approximately 3,220,000 tons of coal during the amended term of the agreement.
- A spot purchase agreement consisting of approximately 220,000 tons of coal to be delivered between January 1, 2015 and December 31, 2015.
- A spot purchase agreement consisting of approximately 28,200 tons of coal to be delivered between February 1, 2015 and March 31, 2015.
- A spot purchase agreement consisting of approximately 14,100 tons of coal to be delivered between January 1 – 31, 2015.
- A spot purchase agreement consisting of approximately 42,300 tons of coal to be delivered between January 1, 2015 and March 31, 2015.
- A spot purchase agreement consisting of approximately 118 tons of coal to be delivered between January 1 – 31, 2015.

Coal railcar lease agreements – To provide for the shipment of the coal supply, the Cooperative entered into lease agreements for the lease of coal railcar trainsets (see Note 15 – Coal railcar trainsets).

Coal railcar maintenance agreement – The Cooperative entered into a 5-year railcar management services agreement, effective January 1, 2013, for the maintenance of the coal railcar trainset leased under the 20-year lease agreement (see Note 15 – Coal railcar trainsets).

Personnel staffing agreement – The Cooperative has a personnel staffing agreement with Sierra, whereby Sierra provides personnel staffing services for all positions, except certain key staff and management positions, who are employees of the Cooperative (see Note 17). The personnel staffing agreement provides that the Cooperative shall pay for the actual and verifiable costs incurred by Sierra for personnel, materials, supplies, and all other direct, indirect, and overhead costs incurred by Sierra in carrying out its responsibilities under the personnel staffing agreement. The term of the staffing agreement is for five years from August 1, 2006.

Note 11 – Commitments and Contingencies (continued)

The agreement is automatically extended for five successive years unless terminated by either party no later than two years prior to the conclusion of such fifth contract year. Neither the Cooperative nor Sierra gave the two-year advance notice of termination, thereby extending the agreement for an additional five-year term.

Approximately 38% of the personnel employed by Sierra are subject to a collective bargaining agreement. Sierra entered into a three-year extension to the collective bargaining agreement effective March 1, 2013.

Office facilities and machinery and equipment agreements – The Cooperative has entered into agreements with Sierra and SWTC, whereby Sierra and SWTC reimburse AEPCO for the use of the Cooperative's office facilities and substantially all of its nongenerating machinery and equipment (see Notes 15 and 17).

Letters of credit – A letter of credit was obtained by the Cooperative from CFC for the purpose of providing credit support for a power purchase agreement with Griffith Energy LLC. As of December 31, 2013, the remaining balance of this letter of credit was $1,653,750. The letter of credit issued to Griffith Energy LLC is subject to annual renewals with the last expiration date not extending past January 31, 2015. The interest rate, if draws were to occur, will be equal to a fixed rate set by CFC, not to exceed the *Prevailing Bank Prime Rate*, as published in the Money Rates column of *The Wall Street Journal*, plus one percent per annum. As a condition of the letter of credit, the Cooperative is required to remain in compliance with the terms and conditions of the Consolidated Mortgage and Security Agreement (see Note 8).

Lines of credit – The Cooperative maintained a line of credit with CFC, which matured June 24, 2014. There were no balances outstanding as of December 31, 2014 and 2013.

On June 5, 2014, the Cooperative entered into a five-year committed unsecured line of credit agreement with CFC for $50,000,000. The interest rate on advances will be calculated at a rate per annum as may be fixed by CFC from time to time or in the case of a LIBOR advance, at a fixed rate per annum equal to LIBOR plus the Applicable Margin. There were no balances outstanding as of December 31, 2014.

The Cooperative also maintains a line of credit agreement with CFC for $250,000 as part of its credit card program. The agreement remains in effect until terminated by either party with a 90-day written notice. Interest rates on all advances under the line of credit will be equal to the total rate per annum as may be fixed by CFC from time to time, which shall not exceed the *Prevailing Bank Prime Rate*, as published in the Money Rates column of *The Wall Street Journal*, plus 1% per annum. The bank prime rate at December 31, 2014 was 3.25%. No amounts were drawn under this line of credit for the years ended December 31, 2014 and 2013.

Note 11 – Commitments and Contingencies (continued)

On August 21, 2014, the Cooperative entered into a five-year committed unsecured line of credit agreement with CoBank for $50,000,000. The interest rate on advances will be calculated at a Base Rate Option, in which a rate per annum equal at all times to the Base Rate plus the Applicable Margin, or at a LIBOR Option, in which a fixed rate per annum equal to LIBOR plus the Applicable Margin. There were no balances outstanding as of December 31, 2014.

Capital lease – Capital lease property and the related liabilities are in substance asset purchases. Assets and liabilities under capital leases are recorded at the lesser of the present value of the minimum lease payments or the fair value of the assets. The assets are amortized over their related lease terms or their estimated useful lives, whichever is less.

On January 28, 2013, the Cooperative entered into a master lease agreement for the lease of substantially all of the Cooperative's vehicles. Individual lease schedules underlying the master lease agreement are entered into as individual vehicles are delivered. Each lease schedule includes a description of the vehicle, the lease term and the monthly rental and other payments due with respect to the vehicle. The term for each vehicle begins on the date each vehicle is delivered and continues as described in the individual schedule.

On October 22, 2013, the Cooperative entered into a master lease agreement to finance the purchase and installation of solar equipment. The period of the lease is sixty (60) months starting January 1, 2014.

Future minimum capital lease payments and present values of the minimum lease payments are as follows as of December 31, 2014:

Years ending December 31,	2015	$ 71,650
	2016	71,650
	2017	80,636
	2018	72,367
	2019	3,241
Total minimum lease payments		299,544
Less amount representing interest		28,256
Present value of net minimum lease payments		271,288
Less current portion		59,525
		$ 211,763

Note 12 – Patronage Capital

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

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

Patronage capital retirement – RUS mortgage provisions require written approval of any declaration or payment of capital credits unless total membership capital exceeds 40% of the total assets of the Cooperative. However, the provisions allow for annual distribution of up to 25% of the margins received by the Cooperative in the preceding year where, after giving effect to any such distribution, total equity equals or exceeds 20% of total assets. The retirements for 2014 and 2013 were $721,358 and $620,763, respectively.

Note 13 – Income Tax Status

The Cooperative is exempt from income taxes under the provisions of Section 501(c)(12) of the Internal Revenue Code, except to the extent of unrelated business income, if any. The Cooperative follows Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 740-10, relating to accounting for uncertain tax positions. As of December 31, 2014 and 2013, the Cooperative does not have any uncertain tax positions. The Cooperative files an exempt organization and unrelated business income tax return in the U.S. federal jurisdiction and the states of Arizona, California, Indiana, Minnesota and North Carolina and is no longer subject to examination by taxing authorities before 2011.

Note 14 – Employee Benefit Plans

Managed Time Off (MTO) – Employees earn paid time-off based on years of service and hours worked in the current period. The maximum accrued MTO for each employee is limited to a predetermined amount as established by policy of the Cooperative's Board of Directors. Any earned MTO not taken by an employee at the time of separation from employment in good standing may be paid in lump-sum as a termination benefit. Each year, employees with MTO exceeding 120 hours may convert up to 80 hours to cash at the employee's current base rate of pay.

Pension plans – The Cooperative has a defined benefit pension plan covering substantially all of its employees. Pension benefits are provided through participation in the National Rural Electric Cooperative Association (NRECA) Retirement Security Plan (RS Plan). The Cooperative contributes a percentage of salaried and union employees' earnings to the program, as prescribed by NRECA. The Cooperative's policy has been to fund retirement costs annually as they accrue. Withdrawal from the RS Plan may result in the Cooperative having a significant obligation to the program.

Note 14 – Employee Benefit Plans (continued)

The Cooperative does not currently intend to withdraw from the plan and accordingly, no provision has been included in the accompanying financial statements.

The NRECA RS Plan is a defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the Internal Revenue Code. It is a multiemployer plan under the accounting standards. The plan sponsor's Employer Identification Number is 53-0116145 and the Plan Number is 333. A unique characteristic of a multiemployer plan compared to a single employer plan is that all plan assets are available to pay benefits of any plan participant. Separate asset accounts are not maintained for participating employers. This means that assets contributed by one employer may be used to provide benefits to employees of other participating employers.

The Cooperative's contributions to the RS Plan in 2014 and 2013 represented less than 5 percent of the total contributions made to the plan by all participating employers. Contributions by the Cooperative to this plan approximated $87,300 and $87,500 for the years ended December 31, 2014 and 2013, respectively. Contributions in 2014 reflect a reduction in the contribution billing rate of approximately 25% resulting from the Cooperative's voluntary decision to prepay RS Plan contributions (See RS Plan prepayment).

In the RS Plan, a "zone status" determination is not required, and therefore not determined, under the Pension Protection Act (PPA) of 2006. In addition, the accumulated benefit obligations and plan assets are not determined or allocated separately by individual employer. In total, the RS Plan was over 80 percent funded on January 1, 2014 and 2013 based on the PPA funding target and PPA actuarial value of assets on those dates.

Because the provisions of the PPA do not apply to the RS Plan, funding improvement plans and surcharges are not applicable. Future contribution requirements are determined each year as part of the actuarial valuation of the plan and may change as a result of plan experience.

The Cooperative offers participation in the NRECA SelectRE Pension Plan to non-union employees hired prior to January 1, 2012 and all union employees regardless of hire date who meet certain minimum service requirements. This plan has 401(k) salary deferral features. Under this plan, the Cooperative matches a percentage of the employees' contributions to the plan. The Cooperative's contributions to the plan were approximately $15,500 for the years ended December 31, 2014 and 2013.

The Cooperative offers participation in the 401(k) Pension Plan to all employees hired after December 31, 2011 who have no prior RS Plan participation history and meet certain minimum service requirements. This plan has 401(k) salary deferral features. Under this plan, the Cooperative matches a percentage of the employees' contributions to the plan. There were no contributions made by the Cooperative to the plan for the years ended December 31, 2014 and 2013.

Note 14 – Employee Benefit Plans (continued)

RS Plan prepayment – On April 29, 2013, the Cooperative voluntarily prepaid contributions of $294,854 to the NRECA RS Plan. The prepayment amount is the Cooperative's share as of January 1, 2013, of future contributions required to fund the RS Plan's unfunded value of benefits earned to date using RS Plan actuarial valuation assumptions. The prepayment was the equivalent of approximately 2.5 times the Cooperative's 2013 annual required contribution and will result in an approximate 25% reduction in the Cooperative's required contributions as of January 1, 2013. The 25% differential in billing rates is expected to continue for approximately 15 years. However, changes in interest rates, asset returns and other plan experience different from expected, plan assumption changes and other factors may have an impact on the differential in billing rates and the 15 year period. In accordance with the guidance provided by RUS to its borrowers, the Cooperative created a deferred debit and will amortize it over 17.5 years starting January 1, 2013.

Deferred compensation programs – The Cooperative offers a program to key employees whereby these employees may elect to set aside a portion of current compensation to be paid out at a later date upon a qualifying event including retirement, termination of employment, death or disability. While this program is still active, there are currently no participants.

The Cooperative offers a program to the Cooperative's Board of Directors whereby a Director may elect to set aside a portion of current compensation to be paid out at a later date upon a qualifying event including retirement, termination of service, death or disability. There is one participant in this program.

The Cooperative offers a program (Pension Restoration Plan) to a select group of management and highly compensated employees whose pension benefits from the RS Plan would be reduced because of limitations on retirement benefits payable under Sections 401(a)(17) or 415 of the Internal Revenue Code. Payments to the employee that would otherwise be paid in pension benefits are paid by the Cooperative as deferred compensation benefits to the extent allowed by the plan upon the participant's attainment of normal retirement age under the RS Plan and termination of employment from the Cooperative. Any benefits payable by the Cooperative under the program are credited by NRECA to an account under the RS Plan. While this program is still active, there are currently no participants.

Note 15 – Operating Leases

Computer equipment – The Cooperative entered into master lease agreements for the lease of substantially all the Cooperative's personal computers and peripheral equipment. Individual certificates of acceptance (COAs) underlying the master lease agreements are entered into as groups of computers and equipment are delivered. The terms of the COAs are for up to four years. Rent expense for the lease of the computer equipment was approximately $214,000 and $251,000 for the years ended December 31, 2014 and 2013, respectively, and is included in administration and general on the accompanying statements of revenues and expenses and unallocated accumulated margins.

Note 15 – Operating Leases (continued)

Coal railcar trainsets – The Cooperative entered into lease agreements for the lease of coal railcar trainsets. Lease payments are included as a component of fuel expense. At December 31, 2014, these lease agreements consist of the following:

- A 20-year lease agreement, effective December 17, 2002. Lease payments under this agreement totaled approximately $377,400 in 2014 and 2013, respectively. The Cooperative has the option of canceling this agreement effective December 31, 2012 subject to the following: (1) the Cooperative notifies the lessor in writing on or before 180 days prior to the effective date of the termination, and (2) the Cooperative pays an additional amount of $5,971 per car for each car terminated.
- A 60-month lease agreement, effective November 23, 2009. This is a full service lease agreement for four railcars to supplement AEPCO's primary train set. Lease payments under this agreement totaled approximately $16,000 and $17,000 in 2014 and 2013, respectively. This lease expired November 30, 2014.
- A 36-month lease agreement, effective December 1, 2014. This is a full service lease agreement for four railcars to supplement AEPCO's primary train set. Lease payments under this agreement totaled approximately $2,000 in 2014.
- A 60-month full service lease agreement for fifteen railcars to supplement AEPCO's primary train set, effective January 20, 2012. Lease payments under this agreement totaled approximately $96,000 and $136,000 in 2014 and 2013, respectively.
- A 56-month lease agreement, effective May 1, 2013. This is an interchange service agreement for 115-120 railcars as may be needed, from time to time, by the Cooperative. Lease payments under this agreement totaled approximately $90,000 and $111,000 in 2014 and 2013, respectively.
- A monthly interchange lease service agreement, effective May 1, 2014, for railcars as may be needed, from time to time, by the Cooperative. Lease payments under this agreement totaled approximately $102,000 in 2014.
- A 12-month lease agreement, effective April 8, 2014 for 114 railcars to supplement AEPCO's primary train set. Lease payments under this agreement totaled approximately $234,000 in 2014.

The following summarizes the future minimum lease payments under operating leases that had initial or remaining lease terms in excess of one year at December 31, 2014:

Years ending December 31,	2015	$ 1,020,600
	2016	702,306
	2017	553,668
	2018	488,652
	2019	377,400
	Thereafter	1,132,200
		$ 4,274,826

Note 16 – Concentration of Customers and Credit Risk

Revenue and accounts receivable for the year ended December 31, 2014 included amounts from three customers, whom each individually represented more than 10% of the total operating revenue and accounts receivable. Revenue from these customers collectively represented approximately 75% of total operating revenue for 2014. The amounts owed from these customers collectively represented approximately 67% of the total accounts receivable balance at December 31, 2014.

Revenue and accounts receivable for the year ended December 31, 2013 included amounts from three customers, whom each individually represented more than 10% of the total operating revenue and accounts receivable. Revenue from these customers collectively represented approximately 76% of total operating revenue for 2013. The amounts owed from these customers collectively represented approximately 67% of the total accounts receivable balance at December 31, 2013.

Note 17 – Related Parties

The Cooperative is a Class B member of SWTC. SWTC is a member-owned, nonprofit Arizona cooperative corporation organized to provide electric transmission and ancillary services to its members and other customers. Class B members of SWTC are collectively represented by one director seated on SWTC's board of directors. Each director is entitled to one vote on each matter submitted to a vote at a meeting of the members. The Cooperative's patronage allocation from SWTC was approximately $8,832,000 and $7,790,000 at December 31, 2014 and 2013, respectively.

The Cooperative is a member of Sierra. Sierra is a member-owned, nonprofit Arizona cooperative corporation organized to provide personnel staffing and energy services and products to its members and other customers. Each member of Sierra is represented by one director seated on Sierra's board of directors. Each director is entitled to one vote on each matter submitted to a vote at a meeting of the members.

The Cooperative has entered into an agreement with Sierra, whereby Sierra provides personnel staffing services (see Note 11 – Personnel staffing agreement). For 2014 and 2013, the Cooperative recorded expenses for personnel staffing services from Sierra totaling approximately $20,251,000 and $20,634,000, respectively.

The Cooperative has entered into agreements with SWTC and Sierra for the use of office facilities and machinery and equipment (see Note 11 – Office facilities and machinery and equipment agreements). For 2014, expense reimbursements received by the Cooperative from SWTC and Sierra totaled approximately $808,000 and $1,352,000, respectively. For 2013, expense reimbursements received by the Cooperative from SWTC and Sierra totaled approximately $661,000 and $1,095,000, respectively.

The Cooperative has entered into an agreement with SWTC for transmission service (see Note 11 – Network service agreement (Class A)). For 2014 and 2013, the Cooperative recorded transmission expenses from this agreement totaling approximately $12,217,000 and $7,956,000, respectively.

Note 17 – Related Parties (continued)

As of December 31, 2014, the Cooperative has recorded accounts payable to SWTC totaling approximately $1,032,000 and no accounts payable to Sierra, and there were approximately $587,000 and $3,564,000 accounts receivable from SWTC and Sierra, respectively. As of December 31, 2013, the Cooperative had recorded accounts payable to SWTC and Sierra totaling approximately $872,000 and $151,000, respectively, and there were approximately $313,000 and $3,681,000 accounts receivable from SWTC and Sierra, respectively. The net receivable or payable are included in the accompanying balance sheets as accounts receivable or payable.

REPORT REQUIRED BY GOVERNMENT AUDITING STANDARDS

MOSS-ADAMS LLP
Certified Public Accountants | Business Consultants

REPORT OF INDEPENDENT AUDITORS ON INTERNAL CONTROL OVER FINANCIAL REPORTING AND ON COMPLIANCE AND OTHER MATTERS BASED ON AN AUDIT OF FINANCIAL STATEMENTS PERFORMED IN ACCORDANCE WITH *GOVERNMENT AUDITING STANDARDS*

To the Board of Directors
Arizona Electric Power Cooperative, Inc.

We have audited, in accordance with the auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States, the financial statements of Arizona Electric Power Cooperative, Inc. (the Cooperative) as of and for the year ended December 31, 2014, and have issued our report thereon dated April 1, 2015.

Internal Control over Financial Reporting
In planning and performing our audit of the financial statements, we considered the Cooperative's internal control over financial reporting (internal control) to determine the audit procedures that are appropriate in the circumstances for the purpose of expressing our opinions on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of the Cooperative's internal control. Accordingly, we do not express an opinion on the effectiveness of the Cooperative's internal control.

A *deficiency in internal control* exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent, or detect and correct misstatements on a timely basis. A *material weakness* is a deficiency, or combination of deficiencies, in internal control, such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected on a timely basis. A *significant deficiency* is a deficiency, or a combination of deficiencies, in internal control that is less severe than a material weakness, yet important enough to merit attention by those charged with governance.

Our consideration of internal control was for the limited purpose described in the first paragraph of this section and was not designed to identify all deficiencies in internal control that might be material weaknesses or significant deficiencies and therefore, material weaknesses or significant deficiencies may exist that were not identified. Given these limitations, during our audit we did not identify any deficiencies in internal control that we consider to be material weaknesses.

REPORT OF INDEPENDENT AUDITORS ON INTERNAL CONTROL OVER FINANCIAL REPORTING AND ON COMPLIANCE AND OTHER MATTERS BASED ON AN AUDIT OF FINANCIAL STATEMENTS PERFORMED IN ACCORDANCE WITH *GOVERNMENT AUDITING STANDARDS* (continued)

Compliance and Other Matters

As part of obtaining reasonable assurance about whether the Cooperative's financial statements are free of material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of our audit, and accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance or other matters that are required to be reported under *Government Auditing Standards*.

We noted certain matters that we reported to the Cooperative's Board of Directors and management in a presentation.

Purpose of this Report

The purpose of this report is solely to describe the scope of our testing of internal and compliance and the results of that testing, and not to provide an opinion on the effectiveness of the Cooperative's internal control or on compliance. This report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the Cooperative's internal control and compliance. Accordingly, this communication is not suitable for any other purpose.

Moss Adams LLP

Portland, Oregon
April 1, 2015

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.2 Provide the name and address of the lender or debt placement agent, and the expected terms of the planned financing, including but not limited to, loan amount, inception date, maturity date, interest rate (for variable interest rates state the basis upon which the rate is dependent and the time interval or frequency the changes are implemented), numerical covenants such as debt service coverage ("DSC"), times interest earned coverage ("TIER"), cash coverage ratio ("CCR"), equity-to-total capital ratio, etc. For amortizing loans, provide an amortization schedule showing the scheduled payments for principal and interest for the full duration of the loan.

Response: AEPCO has applied for financing not to exceed $31,167,500 from the Federal Financing Bank ("FFB") through the United States Department of Agriculture, Rural Utilities Service ("RUS") under the terms of AEPCO's existing mortgage dated August 3, 2009 and any subsequent supplemental mortgage agreements. Parties to the mortgage include AEPCO as debtor, RUS and the National Rural Utilities Cooperative Finance Corporation ("CFC") as mortgagees. The mortgagee addresses are:

Rural Utilities Service
United Stated Department of Agriculture
1400 Independence Ave., SW
Washington, DC 20250-1500

and

National Rural Utilities Cooperative Finance Corporation
20701 Cooperative Way
Dulles, VA 20166

The inception date will be determined when approval of the loan application is received from the RUS. The final maturity date is expected to be December 31, 2034. Each advance shall have its own amortization schedule from issuance to final maturity. The interest rate of each individual loan advance will be determined at the time the advance is made based on treasury rates then in effect. Under the current mortgage, AEPCO is required to maintain a TIER of 1.05 and DSC of 1.0 in the highest two of the three most recent fiscal years. Once the current mortgage is replaced by an indenture (as approved by the Commission in Decision No. 74591), these covenants will be replaced with similar Margins for Interest and DSC requirements.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.3 Provide an explanation of the proposed use of the financing proceeds. If the proceeds of the financing are for funding multiple projects/uses or a construction work plan ("CWP"), provide a detailed list of the projects/uses or a copy of the CWP and the associated cost and the expected funding dates for each. Also provide a copy of any independent external engineering review of the CWP.

Response: AEPCO plans to use the proceeds of this financing to fund certain projects identified in AEPCO's Construction Work Plan 2015-2017. A list of the specific projects included in AEPCO's financing request is attached to the Application as Exhibit A. A copy of the complete work plan is attached to this response. Loan funding will be advanced under this loan package as each project is placed in service.

Please note that some of the projects identified in the attached plan are not listed in Exhibit A to the Application. This is because certain projects in the 2015-2017 plan have been submitted for realignment to AEPCO's S-8 loan, which was initially approved in Decision No. 73728 in Docket No. E-01773A-12-0192. *See* AEPCO's Notice of Proposed Modifications, dated September 24, 2015, attached. If no Staff objection is filed by November 23, 2015, those projects will be deemed approved for funding through the S-8 loan such that they have not been included in the current T-8 loan request.

AZ 028 T8 Apache

2015-2017 CONSTRUCTION WORK PLAN

FOR

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

ARIZONA 28 APACHE

BENSON, AZ

PREPARED BY

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

PROJECT ENGINEERING DEPARTMENT

SEPTEMBER 2014

Arizona Electric Power Cooperative, Inc.'s (AEPCO) 2015-2017 Construction Work Plan was approved by AEPCO's Board in September 2015. Refer to the attached spreadsheet "Summary of Construction Program and Cost" for estimate costs and other project information.

Method of financing

Loan Funds see attachments
General Funds see attachments
Contribution in Aid see attachments

Status of Environmental Report None of the projects in this work plan have environmental approval from the RUS

Estimate Cost Total Cost of the 2015-2017 Construction Work Plan is estimated to be $39,466,500.

Engineering Support Attached see attachment

Registered Engineer ____________________________

Requested By ________________________________Date_______

Approved By _________________________________Date______

Status of Construction______________________________________

CERTIFICATION BY THE ENGINEER

This Construction Work Plan has been prepared in accordance with RUS regulation 7 CFR Part 1710 Subpart F 1710.252 and AEPCO Board Policies 7-6 and 7-7. As no RUS model Construction Work Plan exists for power supply borrows, the distribution borrower model Construction Work plan contained in RUS Bulletin 1724D-101B was used as a guideline with modifications being made as applicable.

I hereby certify that this 2015-2017 Construction Work Plan was prepared by me or under my supervision and that I am a duly registered professional engineer under the laws of the State of Arizona, Registration No. 57707 (mechanical).

Date:_________ By:______________________________

Nathen S. Hatch
Generation Engineering Manager
Arizona Electric Power Cooperative, Inc.

2015-2017 CONSTRUCTION WORK PLAN REPORT

TABLE OF CONTENTS

I. Executive Summary

A. Purpose, Results and General Basis of Study

This report documents the engineering analysis of, and summarizes the proposed construction for, Arizona Electric Power Cooperative, Inc.'s (AEPCO) existing generation plant (Apache Station) for the three (3) year planning period of 2015 through 2017.

Upon completion of construction of the facilities proposed herein, the plant will provide adequate and dependable generation service to AEPCO's members.

The projected total peak system load was taken directly from AEPCO's 2013 Load Forecast Study as approved by AEPCO's Board of Directors on October 9, 2013. Due to the difficulty in predicting the timing for replacement/addition of generation plant components, it is probably that this Construction Work Plan (CWP) will need to be amended during the three (3) year planning period.

A complete list of the planned improvements to existing generation plant along with their estimated costs (based on historical costs, commercially available estimating guides and engineering judgment), required to adequately serve AEPCO's member systems is contained in Subsection I. C. and Appendix IV-A.

B. Service Territory

AEPCO is a non-profit corporation, as defined and organized under the generation and transmission electric cooperative laws of the State of Arizona that provides generation for member system that serve areas of central, southeastern and north-western Arizona, as well as, small areas of New Mexico and California. AEPCO's headquarters is located in Benson, Arizona. AEPCO's only generating plant, Apache Station, is located near Cochise, Arizona.

AEPCO is made up of six (6) Class A Member distribution cooperatives, , and one (1) Class D Member (Valley Electric in Nevada). Three (3) of the Class A distribution cooperatives are All Requirements Members (ARM) and three (3) are Partial Requirements Members (PRM).

C. Existing Resources

AEPCO's Apache Station and several purchase power agreements with other utilities provide the power to serve the loads of AEPCO's members. This power is delivered to the members through transmission services provided by Southwest Transmission Cooperative, Inc. (SWTC).

The Apache Station consists of seven (7) generating units with a total capacity of approximately 601 MW (gross). Steam Unit No. 1 (75 MW) began operation in 1964 and operates in combined cycle mode with Gas Turbine No. 1 (10 MW) which began operation in 1963. Steam Unit No. 1 is self-firing and may be operated independently of Gas Turbine No. 1. Steam Unit No. 1 and Gas Turbine No. 1 operate on natural gas. Although these units are also designed to burn fuel oil, they are not maintained to be fuel oil ready.

Gas Turbine No. 2 (20 MW) began operation in 1972 and Gas Turbine No. 3 (65 MW) began operation in 1975. Steam Turbine Nos. 2 and 3 were originally designed to operate solely on coal. In the eerily 1990's these units were modified to also utilize natural gas as a main fuel. These units, however, continue to operate almost exclusively on coal.

Gas Turbine no. 4 (41 MW) was placed in service in 2002. This unit is a simple-cycle aero-derivative combustion turbine that utilizes natural gas a s the main fuel but may operate on fuel-oil whenever necessary for backup purposes.

Coal for the Apache Station has typically been purchased through long-term contracts (3-years or more). In 2004, AEPCO commissioned a coal blending facility that allows greater flexibility in the procurement of this primary fuel. Natural gas is normally purchased on the spot market and delivered to Apache Station by El Paseo Natural Gas Co. Although Apache Station has signification on-site fuel oil storage capacity, fuel oil has not been fired in the units, other than for testing, for a number of years and relatively little fuel oil is stored on-site.

Unit Nos. 2 and 3 at Apache Station have in the past operated continuously at high capacity factors to serve AEPCO's loads and sales. After the economic slowdown beginning in 2008, the capacity factors slipped into the 70% level. With the recovery from the economic slowdown, Units 2 and 3 are projected to operate at approximately 80 percent capacity factors. Steam Unit No. 1 in combined operation with Gas Turbine No. 1 is expected to be operated only on peak during the summer months. Gas Turbine No. 4 is AEPCO's primary peaking unit and will operate throughout the year during super peak hours. Although economically displaced by the newer Gas Turbine No. 4, Gas Turbine No. 2 will serve as fast start reserves and GT 3 will continue to be maintained as a peaking unit in emergency situations.

AEPCO submitted its BART (Best Achievable Reduction Technology) analysis reports for regional haze to the State of Arizona in 2008. The Environmental Protection Agency (EPA) responded to Arizona's State Implementation Plan (SIP) by partially approving and partially disapproving the SIP in December 2012. AEPCO subsequently developed a much lower cost plan that resulted in emission reductions that are better than BART. EPA has essentially approved AEPCO's alternative proposal and a published revised SIP expected early in 2015. AEPCO's alternative proposal includes several projects that are included in this CWP and they include: ST1 Low NOx Burners, ST2 0.085 NOx Compliance Upgrades, ST3 NOx Reduction Upgrades, and ST3 SNCR Installation. In addition, AEPCO's Unit ST2 will undergo a fuel switch from coal to gas-firing in December 2017, as part of the revised SIP.

Also included in this CWP are Mercury and Air Toxics Standard (MATS) projects for ST2 and ST3. The ST2 Mercury Control project will be implemented for an interim period (between April 2016 and December 2017) before ST2 is converted to combust natural gas only. ST3 Mercury Control will become a permanent installation, operating to the end of its service life.

D. Summary of Construction Program and Cost

Summary of Construction Program and Cost (all project costs are shown in in-service year although there may be cash flow in previous years)

(2015 - 2017 Construction Work Plan, Am. #0)

RUS 740c	App. A Pg	Project Name	Project Number	2015	2016	2017	Total $'s	Amend. # / Chg.
1200 - Generation								
1200.1	1.1	ST2 Particulate Monitor Installation	5-01326	$200,000	$0	$0	$200,000	0 - Original
1200.2	2.1	ST3 Particulate Monitor Installation	5-01327	$200,000	$0	$0	$200,000	0 - Original
1200.3	3.1	ST2 Condenser Air Removal Re-tube	5-01169	$477,000	$0	$0	$477,000	0 - Original
1200.4	4.1	ST2 Generator Auto Voltage Regulator Upgrade	5-01215	$385,000	$0	$0	$385,000	0 - Original
1200.5	5.1	ST2 Yokogawa Replacement	5-01219	$69,000	$0	$0	$69,000	0 - Original
1200.6	6.1	ST3 Mercury Control	5-01239	$2,500,000	$0	$0	$2,500,000	0 - Original
1200.7	7.1	ST2 Air Preheater Basket Replacement	5-01254	$1,596,000	$0	$0	$1,596,000	0 - Original
1200.8	8.1	ST2 Feedwater Heater Level Controls	5-00939	$78,000	$0	$0	$78,000	0 - Original
1200.9	9.1	Miscellaneous Piping Replacement 2015	5-01310	$200,000	$0	$0	$200,000	0 - Original
1200.10	10.1	ST2/3 CWDF Monitoring Well Relocation	5-01284	$100,000	$0	$0	$100,000	0 - Original
1200.11	11.1	ST3 Air Preheater Basket Replacement	5-01294	$1,800,000	$0	$0	$1,800,000	0 - Original
1200.12	12.1	Centac Compressor 'B' Rebuild 2014	5-01303	$400,000	$0	$0	$400,000	0 - Original
1200.13	13.1	ST2 ID Fan Speed Circuit Upgrade	5-01304	$36,000	$0	$0	$36,000	0 - Original
1200.14	14.1	ST2 Mercury Control	5-01308	$1,300,000	$0	$0	$1,300,000	0 - Original
1200.15	15.1	Apache Cathodic Protection Upgrade	5-01309	$136,000	$0	$0	$136,000	0 - Original
1200.16	16.1	ST2 Generator Bushing Replacement	5-01320	$122,000	$0	$0	$122,000	0 - Original
1200.17	17.1	ST3 SDAS Bypass Duct Upgrade	5-01324	$1,100,000	$0	$0	$1,100,000	0 - Original
1200.18	18.1	ST1 Low NOx Burners	5-01242	$0	$2,500,000	$0	$2,500,000	0 - Original
1200.19	19.1	RO Sump Restoration	5-01272	$0	$100,000	$0	$100,000	0 - Original
1200.20	20.1	ST2 Nitrogen Blanket System Install	5-01302	$0	$136,000	$0	$136,000	0 - Original
1200.21	21.1	Miscellaneous Cable Replacment	5-01305	$0	$114,000	$0	$114,000	0 - Original
1200.22	22.1	GT2 Controls Upgrade	5-01306	$0	$350,000	$0	$350,000	0 - Original
1200.23	23.1	Grinnell Fire System Upgrades	5-01307	$0	$60,000	$0	$60,000	0 - Original
1200.24	24.1	GT4 Stage 1 HPC Replacement	5-01210	$0	$128,000	$0	$128,000	0 - Original
1200.25	25.1	ST2 .085 NOx Compliance Upgrades	5-01275	$0	$0	$7,000,000	$7,000,000	0 - Original
1200.26	26.1	ST3 Classifier Replacement	5-00921	$0	$0	$1,345,000	$1,345,000	0 - Original
1200.27	27.1	ST3 Condenser Air Removal Re-tube	5-01170	$0	$0	$491,000	$491,000	0 - Original
1200.28	28.1	ST3 Yokogawa Replacement	5-01220	$0	$0	$67,500	$67,500	0 - Original

RUS 740c	App. A Pg	Project Name	Project Number	2015	2016	2017	Total $'s	Amend. # / Chg.
1200.29	29.1	ST3 SDAS Mist Eliminator Upgrade	5-01229	$0	$0	$400,000	$400,000	0 - Original
1200.30	30.1	ST3 Generator Auto Voltage Regulator Upgrade	5-01241	$0	$0	$430,000	$430,000	0 - Original
1200.31	31.1	ST1 Main Step-Up XFMR Bushing Replace	5-01243	$0	$0	$112,000	$112,000	0 - Original
1200.32	32.1	ST3 NOx Reduction Upgrades	5-01283	$0	$0	$9,970,000	$9,970,000	0 - Original
1200.33	33.1	ST3 SDAS Towers Outlet Upgrade	5-01315	$0	$0	$1,144,000	$1,144,000	0 - Original
1200.34	34.1	ST3 Turbine Blades Upgrade	5-01313	$0	$0	$163,000	$163,000	0 - Original
1200.35	35.1	ST3 Turbine Valve Stem Upgrade	5-01314	$0	$0	$114,000	$114,000	0 - Original
1200.36	36.1	ST3 ID Fans Speed Changer Circuit Upgrade	5-01316	$0	$0	$39,000	$39,000	0 - Original
1200.37	37.1	ST3 SNCR Installation	5-01317	$0	$0	$3,661,000	$3,661,000	0 - Original
1200.38	38.1	ST3 Boiler Splash Screen Upgrade	5-01312	$0	$0	$155,000	$155,000	0 - Original
1200.39	39.1	ST3 HP Feed Water Heaters Level Control	5-01135	$0	$0	$96,000	$96,000	0 - Original
1200.40	40.1	ST3A Replace Mill Throat Liners	5-00852	$0	$0	$192,000	$192,000	0 - Original
		Generation-	Totals:	$10,699,000	$3,388,000	$25,379,500	$39,466,500	

Summary of Construction Program and Cost

II. Basis of Study and Proposed Construction

A. Planning Criteria and Design Goals

AEPCO's planning criteria are based on providing two essential services:

Reliability of Existing Capacity for the member Cooperatives

The reliability of the existing Apache Station facilities continues to be the primary focus of the construction planning effort. This effort focuses on new construction that helps ensure that Apache Station is cost competitive so that the facilities can be utilized to their maximum capability. This effort includes projects which will reduce unit de-rates and unavailability due to environmental compliance issues as well as projects which improve the ability of the units to handle multiple fuels.

Assuring Future Capacity for the Member Cooperatives

The ARM's do not require resources in the near term planning horizon. As a result, new construction of generation capacity has not been included for this planning period. PRM's are currently acquiring new resources as needed on their own behalf, and any plans for those resources are not included in the work plan.

B. Analysis of Current Systems

Partial requirement Members

Three Class A Members have elected to become Partial requirements Members of APECO. Under the partial requirements option, a distribution cooperative continues to meet its proportionate share of AEPCO's financial obligations while receiving an allocated contractual share of the capacity of AEPCO's existing resources. Supplemental resources to serve load and associated energy above Allocated Capacity are acquired by the Partial Requirements Class A Member on its own behalf.

Mohave Electric Cooperative (MEC) elected to exercise the option to become a Partial requirements Class A Member beginning in August of 2001. Sulphur Springs Valley Electric Cooperative (SSVEC) became a Partial Requirements Class A Member effective January 1, 2008, And most recently, Trico Electric Power Cooperative, Inc. (Trico) became a PRM January 1, 2011.

Class A Partial Requirements Members' peak demand forecast is limited to its contracted share of capacity of AEPCO's existing resources in accordance with the Class A Members' Partial Requirement contract with AEPCO. AEPCO does not provide a forecast of energy requirements for the Class A Partial Requirements Members due to the ability to acquire resources beyond native load requirements. The forecast does not attempt to ascertain how the Class A Partial Requirements Members with take energy entitlements; it merely predicts when their capacity will exceed their limits and removes the excess capacity from the forecast of loads found in the Class A Partial Requirements Members' 2013 Load Forecast Study.

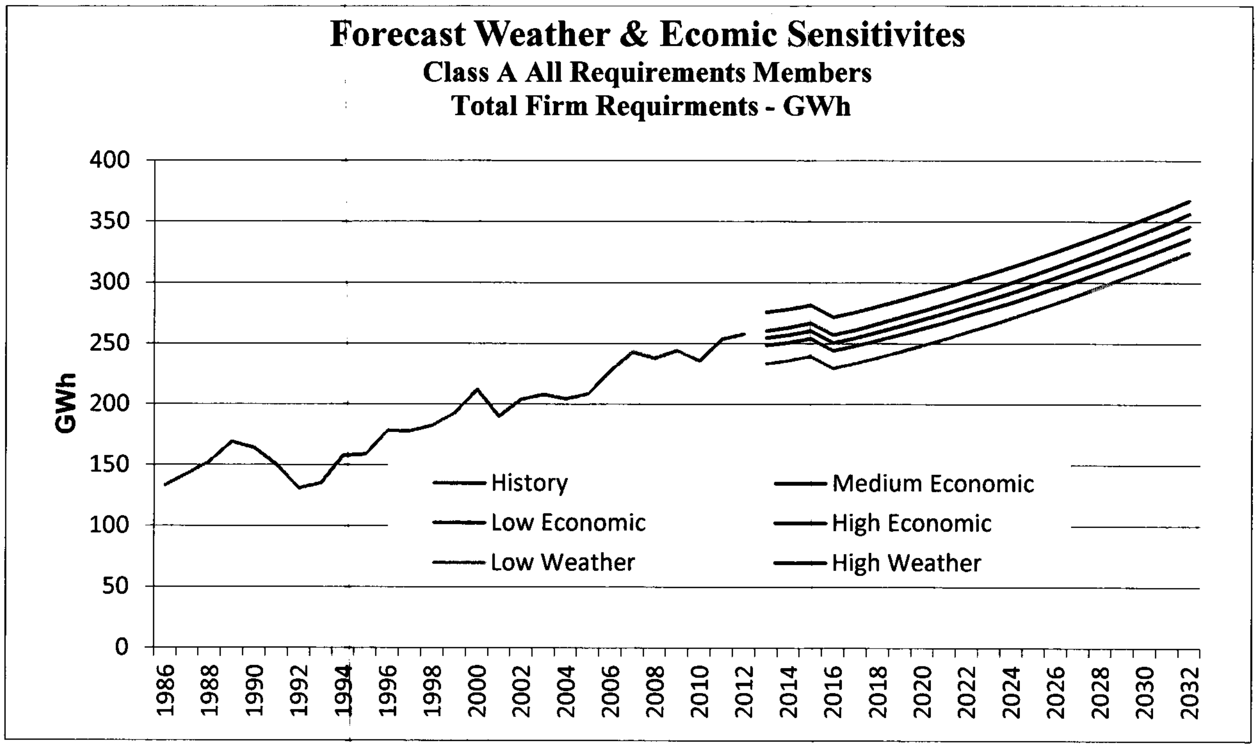
2012 Load Forecast Study – Class A All Requirement Members

AEPCO's 2013 Load Forecast Study was prepared by Sierra Southwest Cooperative Services, Inc. (Sierra) staff on behalf of AEPCO. The Load Forecast Study was approved by the APECO Board of Directors on October 9, 2013. Load projections for this CWP were based on this AEPCO 2013 Load Forecast Study.

AEPCO's 2013 Load Forecast was developed using the individual Class A Member's 2013 Load Forecast Studies, which were aggregated into composite forecast for the three Class A All Requirements Members.

AEPCO is a summer peaking electric system and the forecast for the coincident peak demand for this CWP is formed from the medium economic scenario found in AEPCO's 2013 Load Forecast Study. This forecast is a composite forecast created by aggregating individual forecasts for AEPCO's three (3) Class A All Requirements Member distribution cooperatives. It consists of the medium economic forecast for the distribution cooperatives (Anza, Duncan Valley and Graham County Electric Cooperatives) as found in the respective Members 2013 Load Forecast Studies. The medium economic forecast is based upon the most probable set of economic conditions and normal (10 year average) weather conditions.

The historical and projected energy requirements and summer peak demand for the three (3) Class A All Requirements Members are shown graphically in the following Figures 1 and 2. Member system energy requirements are expected to increase over the three year CWP planning horizon from 244,308 MWh in 2015 to 236,287x MWh in 2017, a 3.3% total decrease and representing an average annual decline of 1.1%. This decrease in energy requirements has been forecasted and will only be temporary. The summer coincident peak demand is expected to decrease over the three-year period from 61.3 MW in 2015 to 60.2 MW in 2017, representing a 1.8% total decrease or annual average decrease of 0.6%.



Forecast Weather & Ecomic Sensitivites
Class A All Requirements Members
Total Firm Requirments - GWh
GWh
400
350
300
250
200
150
100
50
0
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
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History
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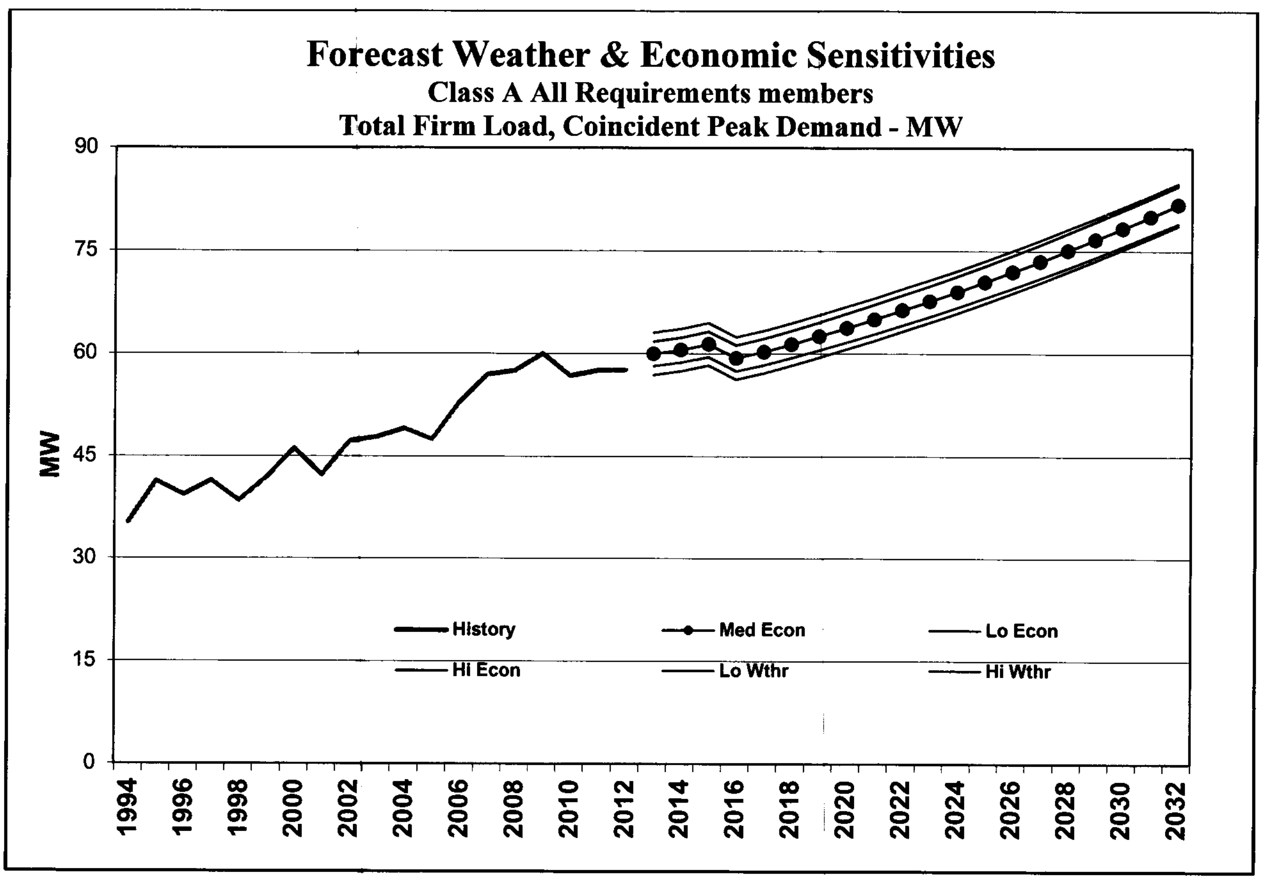
Low Economic
High Economic
Low Weather
High Weather



Forecast Weather & Economic Sensitivities
Class A All Requirements members
Total Firm Load, Coincident Peak Demand - MW
MW
90
75
60
45
30
15
0
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
History
Med Econ
Lo Econ
Hi Econ
Lo Wthr
Hi Wthr

C. Maintenance Program and Service Reliability

Arizona Electric Power Cooperative, Inc. (AEPCO) has developed a generation system maintenance program that maximizes AEPCO's total available resources, while at the same time employs sound and prudent utility practices. The goal of AEPCO's maintenance program is to maintain very high availability and operating efficiency of all generation equipment.

To accomplish the goal of the maintenance program, AEPCO maintains a highly trained, skilled and competent maintenance work force including managers, supervisors and technicians, who are dedicated to being the best possible steward for the assets of APECO's member owners.

In 2006 AEPCO purchased a new financial and accounting software system from the SAP Corporation. The system included two modules that are employed by AEPCO to meet its commitment to providing the most efficient and effective maintenance program. One system tool used is the Plant Maintenance (OM) module that performs scheduling, record keeping, and reporting. Another system tool is the Materials Management (MM) module that performs inventory control, purchasing, and cost tracking.

All equipment is assigned an independent identification number, which tracks the maintenance cost associated with that piece of equipment. In addition, each piece of equipment retains a history of all material, labor and work performed during its lifetime.

The MM module incorporates a parts management (inventory) program, which allows immediate knowledge of materials on hand, materials on order, expected delivery time, materials usage, as well as the capability to allocate materials during the planning process.

In addition to the SAP system, AEPCO has established a Reliability Centered Maintenance Program (RCM). This program focuses on providing maintenance for equipment based on the most cost effective maintenance schedule for that particular piece of equipment rather than on a generic preventive maintenance schedule. Although this program requires sophisticated equipment and training to do the proper monitoring, it is showing results in reducing maintenance costs while being more effective in preventing unscheduled equipment downtime.

Maintenance Staffing

The Apache Station's maintenance staff is comprised of a Manager of Instrument and Electrical Maintenance, Manager of Mechanical Maintenance, Manger of Maintenance

Planning and Reliability, (2) Maintenance Planners, A Reliability Centered Maintenance (RCM) Planning Coordinator, (8) Mechanics, (4) Certified Welders, (1) Machinist, (1) Insulator, (6) Instrument Technicians, (7) Electricians, (1) CEM Technician, (2) RCM Technicians, (5) warehouse personal, and (1) Rolling Equipment Mechanic.

The normal work schedule for maintenance coverage is Monday through Friday. During periods of significant activities, the capability exists to re-schedule work crews as required.

Maintenance support is provided by the Plant Engineering Group located at the Apache Station. This group is comprised of (2) Mechanical Engineers and (1) Electrical Engineer, and (1) Engineering Administrator.

In addition to providing engineering support for general maintenance activities, the Plant Engineering Group oversees the maintenance program for the Turbine/Generators and the Combustion Turbines. Additional support is provided by the Controls/CEM Group and the O&M Projects Coordinator.

Maintenance Program

The Apache Station's Maintenance Program consists of four major area:

- Predictive Maintenance
- Preventive Maintenance
- Corrective Maintenance
- Breakdown Maintenance

Also, there are two scheduled events:

- Major Overhaul
- Minor Overhaul

Predictive Maintenance

Predictive Maintenance is performed on a scheduled basis to establish the need for listed categories such as preventative or corrective maintenance

AEPCO has the equipment and expertise to perform vibration monitoring diagnosis, including electronic data exchange with industry vibration experts if outside assistance is necessary.

AEPCO also has in-house capabilities to perform ultrasonic thickness measurements to detect erosion or corrosion, and sonic measurements to detect erosion or corrosion, and sonic measurements to detect air leaks or machinery problems. The use of infrared temperature detection to locate developing problems or sources of heat loss is also employed. A laser alignment system is used to check and align critical equipment. Additionally, various oil analyses, vibration, ultrasonic and electrical tests on large motors, generators and switchgear are completed on a scheduled basis.

Preventative Maintenance

This type of work is predetermined as to the tasks to be performed, based on manufacture's recommendations, personal experience, and review of history and industry experience.

The work is automatically generated within SAP Plant Maintenance system based on calendar time intervals, hours of use, or other measureable criteria that may be established.

Other needed maintenance, which is not included in the work assignment and is observed during the course of performing the preventative maintenance task is accomplished at the time, if possible, and documented. Any additional work observed and not completed, is identified and a Corrective maintenance Request is generated with the task being scheduled and completed at a later date.

Currently, Preventative Maintenance is 21-25% of the total maintenance effort.

Breakdown Maintenance

This type of work is unpredictable i.e. boiler tube failures, equipment bearing failures, ash line breakages and lightning damage. Typically the work is underway prior to the maintenance request being generated or assigned. The same degree of documentation and accounting is completed with this type of work as with the others.

Currently, Breakdown Maintenance is 18-23% of the total maintenance effort.

Major Overhauls

Each unit at Apache Station is taken out of service every six years for major disassembly, inspection and repair. The typical duration of this outage is six weeks. The extent of this work is determined by manufacture's recommendations, results of previous inspections, predictive maintenance findings and industry experience.

The Turbine/Generator is totally dissembled during these outages, inspected, cleaned and needed repairs made.

The Boiler is inspected with ultrasonic measurements taken. Tube samples are removed for analysis to determine the conditions of pressure parts, and any repairs that can be accomplished are completed at this time.

Pollution control equipment, such as electrostatic precipitators and sulfur dioxide absorber systems, are inspected and repaired.

The unit auxiliary equipment is cleaned, inspected, lubrication performed and any needed repairs made.

Minor Overhauls

Each unit at Apache Station is taken out of service every thirty-six months for minor disassembly, inspection and repair. They typical duration of this outage is four weeks. Each category of maintenance, Preventative and Corrective are completed during the outage. This is the opportune time to perform work on equipment that cannot be taken out of service at other times, without affecting unit capability.

The boiler is inspected with ultrasonic measurements taken and tube samples removed for analysis to determine pressure parts condition. Also, any repairs needed that can be accomplished are also completed.

Every three years as part of either a minor or major overhaul, the Turbine/Generator control valves, main stop valves and reheat intercept/stop valves are disassembled, cleaned, inspected and needed repairs made. Additionally, other items are completed as well, based on previous inspections, manufacture's recommendations or industry experience.

The auxiliary equipment is cleaned, inspected, lubrication performed and any needed repairs made during all scheduled outages.

General

Information that is available to the maintenance manager from the SAP System is:

- Current Maintenance Status
- Scheduled Maintenance Assignments with parts
- Supervisor Follow-up/Critical Overdue Reports
- Maintenance performed Service History/Costs
- Work Order Scheduling
- Manpower Scheduling
- Repair Parts – current Stock Status

AEPCO's maintenance system and accounting processes require that all work completed by Maintenance personnel must be reflected on a "work order". Further, that all work no matter how large or small, is reduced to a maintenance request, prioritized, assigned proper accounting, planned, scheduled and completed. There are a large number of maintenance requests in the AEPCO system, approximately 700-900 per month. Some of these work requests require an outage, or are lower in priority, etc. The backlog, at times, of work requests can appear to be a large number

The system backlog is under constant review to reassess work order priorities. For higher priority work which needs to be completed, providing that the AEPCO work force is unable to accommodate the need, AEPCO will bring in the appropriate craft workers to subsidize the AEPCO work force. AEPCO also utilizes contractors where appropriate. Low priority work is completed when time permits and used as fill-in around other, higher priority work.

The forgoing information concerning AEPCO's Generations Maintenance program is intended to give general overview of the produces used. It is AEPCO's believe that it has in place an effective and efficient maintenance program.

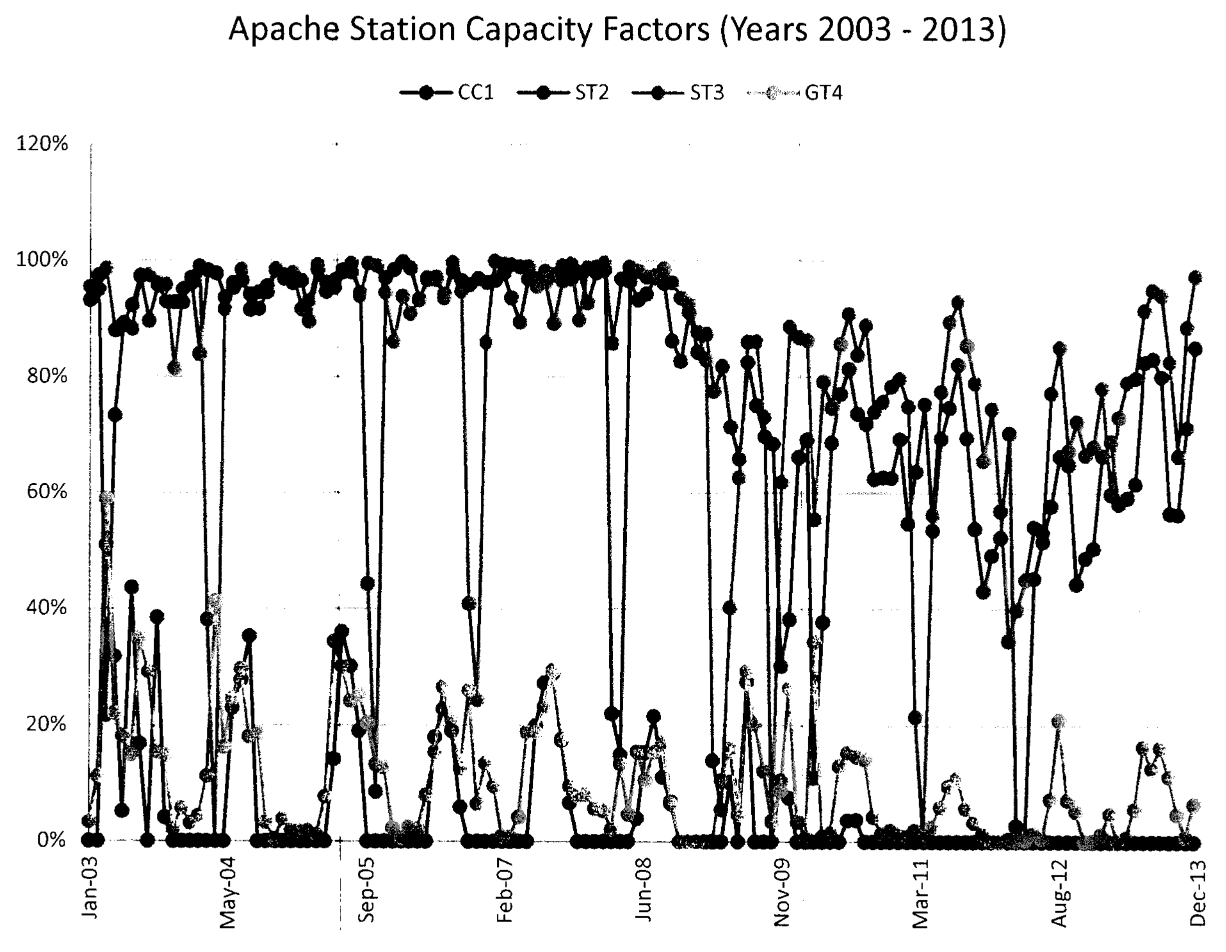
D. Historical and projected System Data

Apache Station capacity Factory and Peak History

Apache Station's gas and coal fired steam units (ST1, ST21, and ST3) historically have reached peak outputs year round with increased capacity factor in the summer months. The primarily gas-fired ST1 operating in combined cycle with combustion turbine (GT) GT1 will peak primarily in the summer months and may be used to provide capacity when needed to cover outages and overhauls on ST2 and ST3. GT4 is used as a year round peaking unit. Combustion turbines GT2 and GT3 are also used as peaking units, but are dispatched much less than GT4 due to their higher heat rates.

Overall Capacity factors for all the steam units have increased from the 50 percentile to the high 80 percentile. The causes of this increased output are the economic recovery and the increasingly scarce availability of cheaper combined-cycle capacity.

The following chart indicates monthly capacity factors for GT4, CC1, ST2 and ST3 over the past ten years. Note that seasonal variations in capacity factor for ST2 and ST3 are minimal.



Apache Station

The following table shows Equivalent Forced Outage Rates (EFOR) and Equivalent Availability Factors (EAF) for Apache Station units ST2, ST3, GT4 and CC1 (ST1 and GT1 combined cycle). Due to the substantially lower operating hours of the remaining units (GT2 and GT3), they are not presented here.

APACHE STATION

	EFOR						***EAF***				
Year	ST1	ST2	ST3	GT1	GT4	Year	ST1	ST2	ST3	GT1	GT4
2003	1.11	1.36	1.13	31.76	58.58	2003	93.26	90.82	97.55	84.20	75.16
2004	5.06	0.40	0.41	2.76	6.15	2004	98.33	98.55	85.62	98.68	97.29
2005	16.58	2.96	0.88	1.15	11.22	2005	85.44	86.86	98.36	99.10	97.20
2006	1.12	0.66	2.96	13.48	12.28	2006	89.83	99.29	85.24	66.19	95.93
2007	54.19	1.13	1.22	2.15	19.28	2007	76.21	98.17	98.77	90.23	94.63
2008	36.26	1.75	0.38	10.61	61.85	2008	94.31	85.33	98.55	93.24	79.65
2009	77.17	1.94	10.93	71.11	50.45	2009	31.97	88.94	79.76	52.26	81.66
2010	0.28	1.64	0.30	46.89	18.59	2010	43.57	87.43	97.03	44.06	95.36
2011	2.89	1.35	0.76	9.92	24.69	2011	96.18	96.65	82.96	98.58	96.55
2012	0.00	1.83	1.44	0.00	3.27	2012	99.40	80.40	98.31	99.77	98.94
2013	0.00	4.23	0.73	66.42	11.56	2013	100.00	91.62	95.73	95.62	90.25

NATIONAL AVERAGES FOR COMPARABLE UNITS

	EFOR						***EAF***				
Year	ST1	ST2	ST3	GT1	GT4	Year	ST1	ST2	ST3	GT1	GT4
2003	8.05	6.86	6.86	15.66	15.66	2003	88.88	84.84	84.84	92.19	92.19
2004	10.78	5.32	5.32	11.13	11.13	2004	86.93	86.84	86.84	91.04	91.04
2005	9.34	7.09	7.09	13.28	13.28	2005	88.26	84.95	84.95	93.44	93.44
2006	8.98	6.91	6.91	7.12	7.12	2006	87.66	85.49	85.49	91.67	91.67
2007	10.51	7.19	7.19	19.65	19.65	2007	86.99	83.71	83.71	91.16	91.16
2008	15.30	6.93	6.93	25.84	25.84	2008	84.90	84.73	84.73	90.06	90.06
2009	20.10	18.00	18.00	33.45	33.45	2009	84.06	82.46	82.46	87.12	87.12
2010	17.19	7.03	7.03	31.62	31.62	2010	83.35	84.46	84.46	85.60	85.60
2011	6.02	6.84	6.84	6.02	37.57	2011	83.96	84.59	84.59	83.96	88.57
2012	6.30	7.42	7.42	6.30	46.15	2012	84.50	85.23	85.23	84.50	87.40
2013	6.18	8.13	8.13	6.18	60.52	2013	85.49	85.83	85.83	85.49	86.03

*Note: Starting in 2011 GADS combined ST1 & GT1 into a combined cycle plant for comparison purposes.

Apache Station's coal fired units typically have lower than average forced outage rates and higher than average availability factors based on Generating Availability Data System's (GADS) national data and reporting criteria. This is attributable to active maintenance and improvement programs and to the relative young age of ST2 and ST3 compared to the national average. AEPCO recognizes that ST2 and ST3 are well into their expected lives and will require increasing expenditures for maintenance and capital improvements in order to maintain their place in a competitive environment.

Capital Project Analysis

Project Name:	ST2 Particulate Monitor Installation	
Project Location:	Apache	
Project Number:	5-01326	
Estimated Cost:	$ 200,000	*Including* $ 3,500 IDC
In Service Month/Year:	10/2015	
Anticipated Funding Source:	$ 196,500	RUS Loan Funds
	$ 3,500	General Funds
	$ 0	Other
RUS Environmental Approval:	Anticipated	
RUS General Funds Approval:	Not Required	

Recommendation:

Install a particulate monitor to directly measure stack particulate matter emissions. Currently particulate matter emissions are measured indirectly by stack opacity monitors.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	18 %
Payback:	5.1 Year(s)
Payback Basis:	Avoidance of quarterly testing for compliance.

Background, Justification, and Need:

ST2 was constructed with an electrostatic precipitator for particulates (fly ash) removal and a wet scrubber for sulfur dioxide (SO2) control. In addition to removing SO2, the wet scrubber helps remove remaining particulates from the flue gas stream. One result of this process is saturated flue gas leaving the scrubbers. This moisture present in the flue gas will not allow the opacity monitors to function properly. Opacity monitors indicated the clarity or opaqueness of the stack as a surrogate for particulate matter emissions. When the flue gas stream starts to condense, the moisture is picked up by the opacity monitors. These high opacity indications from moisture present will blind the monitor to any other particulate matter that may be present in the stack.

Capital Project Analysis

Historically this problem has been mitigated by the bypassing of a small amount of hot flue gas around the scrubbers to re-heat and dry out the flue gas stream. The result was a dry stream that functioned well with opacity monitoring.

Recently the emission limits for SO2 and mercury have been reduced to the point where the flue gas needs to be fully treated to meet the new emission limits. When all of the flue gas passes through the scrubbers, the moisture present in the flue gas causes the opacity monitors to indicate 40 to 50% opacity even though actual opacity is much less. The operating permit for ST2 requires opacity readings to be below 21%.

The installation of a different technology to measure and report particulate matter directly rather than using opacity as a surrogate will solve the opacity issues. A particulate monitor is not affected by moisture because the monitor dries out the sample prior to analyzing it for actual particulates.

<u>Alternatives Reviewed:</u>

Option 1 – Do Nothing

The opacity monitor will not accurately measure opacity of a wet stack; EPA method 9 tests will need to be conducted daily. Method 9 tests are visual inspections made on the flue gas as it exits the stack. For this to work, optimal conditions need to be present. These measurements cannot be made during periods of darkness or when an overcast sky is present. Duct opacity measurements can be taken and reported upstream of the absorber towers, but these measurements will be higher than actual emissions. The absorber towers remove some particulate from the flue gas stream.

Option 2 – Change the Opacity Measurement Point

If the opacity was reported from the duct opacity monitors (rather than the stack opacity monitors), the moisture will not be present in the flue gas stream. However, the absorber towers also remove some particulate matter from the flue gas stream so the duct-measured opacity will be higher than the actual unit emissions.

Option 3 – Dry the Flue Gas Stream

By installing some steam coil air heaters, the temperature of the flue gas in the stack could be raised above its dew point. By raising the temperature of the flue gas above its dew point, the opacity monitors will be able to read true opacity readings. The amount of energy required to heat up the flue gas stream above its dew point will drastically increase the heat rate of the unit. This is the highest cost solution.

Capital Project Analysis

Option 4 – Install Particulate Monitors
Install particulate monitors in the stack so true readings of particulate emissions can be reported in a wet stack environment.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends Option 4 since it is the least expensive and most accurate way to maintain environmental compliance.

Capital Project Analysis

Project Name:	ST3 Particulate Monitor Installation
Project Location:	Apache
Project Number:	5-01327
Estimated Cost:	$ 200,000 *Including* $ 3,500 IDC
In Service Month/Year:	10/2015
Anticipated Funding Source:	$ 196,500 RUS Loan Funds
	$ 3,500 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Install a particulate monitor to directly measure stack particulate matter emissions. Currently particulate matter emissions are measured indirectly by stack opacity monitors.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	18 %
Payback:	5.1 Year(s)
Payback Basis:	Avoidance of quarterly testing for compliance.

Background, Justification, and Need:
ST3 was constructed with an electrostatic precipitator for particulates (fly ash) removal and a wet scrubber for sulfur dioxide (SO2) control. In addition to removing SO2, the wet scrubber helps remove remaining particulates from the flue gas stream. One result of this process is saturated flue gas leaving the scrubbers. This moisture present in the flue gas will not allow the opacity monitors to function properly. Opacity monitors indicated the clarity or opaqueness of the stack as a surrogate for particulate matter emissions. When the flue gas stream starts to condense, the moisture is picked up by the opacity monitors. These high opacity indications from moisture present will blind the monitor to any other particulate matter that may be present in the stack.

Historically this problem has been mitigated by the bypassing of a small amount of hot flue gas around the scrubbers to re-heat and dry out the flue gas stream. The result was a dry stream that functioned well with opacity monitoring.

Recently the emission limits for SO2 and mercury have been reduced to the point where the flue gas needs to be fully treated to meet the new emission limits. When all of the flue gas passes through the scrubbers, the moisture present in the flue gas causes the opacity monitors to indicate 40 to 50% opacity even though actual opacity is much less. The operating permit for ST2 requires opacity readings to be below 21%.

The installation of a different technology to measure and report particulate matter directly rather than using opacity as a surrogate will solve the opacity issues. A particulate monitor is not affected by moisture because the monitor dries out the sample prior to analyzing it for actual particulates.

Alternatives Reviewed:

Option 1 – Do Nothing

The opacity monitor will not accurately measure opacity of a wet stack; EPA method 9 tests will need to be conducted daily. Method 9 tests are visual inspections made on the flue gas as it exits the stack. For this to work, optimal conditions need to be present. These measurements cannot be made during periods of darkness or when an overcast sky is present. Duct opacity measurements can be taken and reported upstream of the absorber towers, but these measurements will be higher than actual emissions. The absorber towers remove some particulate from the flue gas stream.

Option 2 – Change the Opacity Measurement Point

If the opacity was reported from the duct opacity monitors (rather than the stack opacity monitors), the moisture will not be present in the flue gas stream. However, the absorber towers also remove some particulate matter from the flue gas stream so the duct measured opacity will be higher than the actual unit emissions.

Option 3 – Dry the Flue Gas Stream

By installing some steam coil air heaters, the temperature of the flue gas in the stack could be raised above its dew point. By raising the temperature of the flue gas above its dew point, the opacity monitors will be able to read true opacity readings. The amount of energy required to heat up the flue gas stream above its dew point will drastically increase the heat rate of the unit. This is the highest cost solution.

Option 4 – Install Particulate Monitors

Install particulate monitors in the stack so true readings of particulate emissions can be reported in a wet stack environment.

Safety Considerations:

None

Environmental Considerations:

N/A – Categorical Exclusion

Conclusion:

Staff recommends Option 4 as it is the least expensive and most accurate way to maintain environmental compliance.

Capital Project Analysis

Project Name:	ST2 Condenser Air Removal Re-tube
Project Location:	Apache Station
Project Number:	5-01169
Estimated Cost:	$ 477,000 *Including* $ 7,500 IDC
In Service Month/Year:	5/2015
Anticipated Funding Source:	$ 454,500 RUS Loan Funds
	$ 7,500 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
The air removal section of the condenser is exposed to corrosion and erosion. Numerous tubes in this section have been plugged. Engineering recommends the replacement of the air removal section tubes in the condenser.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	0.01 %
Payback:	9.5 Year(s)
Payback Basis:	The payback is based on unit deration of 100MW for one week at $30/MWh differential cost. 10% likelihood (has happened once already).

Background, Justification, and Need:
The air removal section of the condenser is being damaged from corrosion and erosion caused by steam impingement and oxidation. A detailed inspection report from an outside service firm (Conco) indicates that the tubes outside the air removal section are in good condition. The air removal section is approximately 450 tubes. Replacement of this section would reduce unit deratings caused by air removal section tube leaks and would also improve efficiency.

Alternatives Reviewed:
Option 1 – Do Nothing
Continue to operate in current condition. Recent testing reports on the air removal section indicate significant wall thinning on some tubes. Reduced efficiency and forced unit deratings will continue.

Capital Project Analysis

Option 2 – Further Plug Thinning Tubes in the Air Removal Section
Perform additional tube eddy-current testing to determine which tubes require plugging. Remove tube samples from the unit to determine the root cause of tube thinning. This will increase unit reliability with a minimal amount of expenditure.

Option 3 – Replace Tubes with Like-kind Material Replacement
Replace the existing air removal condenser tubes with in-kind 90/10 copper/nickel tubes. This will increase unit reliability by decreased unit deratings from the already deteriorated air removal section.

Option 4 – Replace Tubes with Improved Alloy Material
Replace the existing air removal condenser tubes with improved alloy materials not subject to high corrosion rates. This will increase unit reliability by decreased unit deratings from the already deteriorated air removal section.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 4, replace the condenser air removal section tubes with improved alloy material, is the preferred option and is recommended by Engineering as the most economical solution.

Capital Project Analysis

Project Name:	ST2 Generator Auto Voltage Regulator Upgrade
Project Location:	Apache Station
Project Number:	5-01215
Estimated Cost:	$ 385,000 *Including* $ 5,000 IDC
In Service Month/Year:	5/2015
Anticipated Funding Source:	$ 355,660 RUS Loan Funds
	$ 7,340 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

<u>Recommendation:</u>
Replace the existing General Electric automatic voltage regulator (AVR) control system on unit ST2.

<u>Economics / Justification:</u>

Project Type:	Ordinary Replacement
Budget Priority Code:	2.F – Managerial and/or Board discretion
IRR:	51 %
Payback:	3.4 Year(s)
Payback Basis:	Risk of 1 in 25 that the current system will fail. Risk escalated to 1 in 10 after three years.

<u>Background, Justification, and Need:</u>
The main power generator converts the mechanical energy of the steam turbine into electricity. The generator provides electrical current for transmission system loads. The current is maintained at a constant voltage by the important automatic voltage regulating control system installed on each unit. In order to generate the electricity, the generator field is excited with DC power. Regulation of this DC excitation maintains the output voltage. This AVR control system also controls MW, MVAr, frequency, and power factor. This control system is essentially the brain of the generator.

The current AVR control system is a General Electric model EX2000. The system was installed on unit ST2 in 1998. GE stopped producing the EX2000 in 2004. GE has notified the industry that the EX2000 equipment will no longer be supported after the year 2010. In order to preserve the design reliability of the unit, this system needs to be replaced.

Capital Project Analysis

Alternatives Reviewed:
Option 1 – Do Nothing
Doing nothing will result in an increasing risk of a major forced outage should the current control system fail. A card or component failure means the possibility of repair but will require creative and time-intensive repair due to the lack of OEM support.

Option 2 – Seek a Third Party to Repair Components
This option has been tried without much success. Use of a third party to repair components also introduces more risk to system reliability and typically does not carry any warranty of work performed should an able and competent third party be located.

Option 3 – Replace the Existing AVR Control System
This option will require the specification and bidding of a new automatic voltage control system for unit ST2 and will restore reliability concerns of this subsystem.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 2, replace the existing automatic voltage control system, is the prudent, reliable, and lowest cost option for AEPCO's member customers.

Capital Project Analysis

Project Name:	ST2 Yokogawa Replacement
Project Location:	Apache Station
Project Number:	5-01219
Estimated Cost:	\$ 69,000 *Including* \$ 700 IDC
In Service Month/Year:	12/2015
Anticipated Funding Source:	\$ 67,600 RUS Loan Funds
	\$ 700 General Funds
	\$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Replace the existing, obsolete 15-year-old Yokogawa data acquisition and alarming hardware on unit ST2. This project will also include the labor to remove redundant data points where applicable.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	3.B – Economic Justification
IRR:	380 %
Payback:	0.2 Year(s)
Payback Basis:	Based on unit system failure and two-week outage to replace.

Background, Justification, and Need:
The Apache Station control room originally had installed a number of data strip-chart recorders. This required the continual storage of rolls of paper with actual operating data (temperatures, pressures, etc.). Approximately 15 years ago, these strip-chart recorders were replaced by data acquisition hardware that stored the data digitally. This was very beneficial because old data could now be trended and analyzed to assist with troubleshooting upset conditions of the units.

The data acquisition systems installed 15 years ago are now obsolete and need to be replaced. This project will upgrade the data acquisition hardware and includes the labor to disconnect the input wiring and reconnect it to the new hardware.

Alternatives Reviewed:
Option 1 – Do Nothing
If nothing is done, the existing data acquisition hardware will continue to operate until a system component fails. Any failure might mean that the hardware becomes inoperable. Although this

hardware does not actually control the units, it provides important information to the operators and engineers.

Option 2 – Replace the Existing Yokogawa Hardware
This project will replace the existing Yokogawa data acquisition system of unit ST2 that is no longer supported (technical and spare parts) by the original equipment manufacturer. This will restore the reliability of data acquisition for unit ST2.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
By replacing the existing Yokogawa hardware, important operating data can continue to be viewed by the operators, stored for future use, and analyzed by engineering. Option 2 is the recommended option.

Capital Project Analysis

Project Name:	ST3 Mercury Control	
Project Location:	Apache	
Project Number:	5-01239	
Estimated Cost:	$ 2,500,000	*Including* $ 48,000 IDC
In Service Month/Year:	11/2015	
Anticipated Funding Source:	$ 2,452,000	RUS Loan Funds
	$ 48,000	General Funds
	$ 0	Other
RUS Environmental Approval:	Anticipated	
RUS General Funds Approval:	Anticipated	

Recommendation:
Install an Activated Carbon Injection (ACI) system on ST3 to provide for the oxidation and removal of mercury from the flue gas.

Economics / Justification:

Project Type:	New Construction
Budget Priority Code:	4.B – Code, government regulations, etc.
IRR:	1884 %
Payback:	0.1 Year(s)
Payback Basis:	Payback based on $2/MMBtu difference in gas and coal, 10,300 heat rate, and 80% CF.

Background, Justification, and Need:
The Environmental Protection Agency (EPA) issued a standard to regulate the amount of mercury emissions from a power plant. This rule, known as the Mercury and Air Toxins standard (MATS), becomes effective April 2015 unless a utility applies for and is granted a one-year extension. According to MATS, the mercury emission standard is 1.2 pounds of mercury for every trillion Btu burned in the boiler for sub-bituminous coal. Apache station fires sub-bituminous coal and is therefore going to be held to the MATS limit of 1.2 lbs./TBtu.

In November 2013 Apache Station applied for the one-year extension. This extension was granted in December 2013. Starting in April 2016, all units at Apache Station will need to emit less than 1.2 pounds of mercury for every trillion Btu burned. Currently the mercury emissions of ST3 are in the 3 to 5 lbs./TBtu range. Calcium bromide has been added to the coal as it is elevated up to the bunkers since 2010 to aid in the oxidation and, therefore, removal of mercury. This oxidizer does a good job of aiding the removal of mercury from the system, but it alone will not allow ST3 to achieve the mercury limits.

Capital Project Analysis

In May 2014 testing was performed with different activated carbons by injecting them into the flue gas ducts to determine if this technology would enable ST3 to achieve the emissions limits. The testing found that neither calcium bromide nor activated carbon injection alone would achieve the emission target of 1.2 lbs./TBtu. When both technologies were used simultaneously, however, the emissions limits were achieved. If ST3 is to keep burning coal past the MATS deadline of April 2016, a different mercury control technology must be employed to achieve the standard. By installing an ACI system to work in conjunction with the existing CaBr2 system, compliance is obtainable.

<u>Alternatives Reviewed:</u>
Option 1 – Do Nothing
Doing nothing will allow ST3 to burn coal up until the MATS deadline takes affect (April 2016). After the MATS deadline, the unit could not comply with regulatory standards and would receive significant fines up to the loss of an operating permit.

Option 2 – Install Gore Mercury Modules in the Top of the Scrubber
This option employs relatively new technology from W.L. Gore & Associates called mercury modules. These mercury modules are a passive technology that have a semi-permeable membrane, a deriving of polytetrafluoroethylene (PTFE), which reacts with the mercury in the flue gas to absorb mercury. Once the mercury is absorbed by the modules, the flue gas passes through the modules and is emitted less the mercury. The mercury modules continue to collect the mercury until they reach their service life and have to be disposed of and replaced.

Option 3 – Install Mercury Oxidation Catalyst
This option requires the installation of a catalyst that works very similar to a Selective Catalytic Reduction (SCR). The ductwork is enlarged at a convenient location and mercury oxidizing catalysts are installed to react with the mercury in the flue gas. The catalyst aids to oxidize the mercury in the flue gas so that it can be collected in the scrubber towers for removal. The mercury catalyst will then need replacing at specified intervals as it degrades over its useful life.

Option 4 – Switch Fuel from Coal to Natural Gas
This option would not require any additional mercury removal equipment as natural gas emissions do not contain any mercury. However, this would yield a more expensive operation than removing mercury from the coal combustion process.

Option 5 – Install Activated Carbon Injection
This option employs an active system that can be adjusted up or down to change the mercury oxidation and removal required for the different types of coal to stay within the EPA emission limits. Powdered activated carbon is injected into the flue gas ducts. The brominated carbon reacts with the mercury to oxidize and capture it. Once captured, it is collected in the wet absorber towers and removed with the waste slurry.

<u>Safety Considerations:</u>
None

Capital Project Analysis

<u>Environmental Considerations:</u>
N/A – Categorical Exclusion

<u>Conclusion:</u>
Staff recommends Option 5 as it is the lowest cost known operational solution to MATS compliance.

Capital Project Analysis

Project Name:	ST2 Air Preheater Basket Replacement	
Project Location:	Apache	
Project Number:	5-01254	
Estimated Cost:	$ 1,596,000	*Including* $ 9,300 IDC
In Service Month/Year:	4/2015	
Anticipated Funding Source:	$ 1,586,700	RUS Loan Funds
	$ 9,300	General Funds
	$ 0	Other
RUS Environmental Approval:	Anticipated	
RUS General Funds Approval:	Anticipated	

Recommendation:
The existing air preheater baskets are original equipment and are nearing the end of their service life. New like-kind baskets will lower fuel consumption and, subsequently, unit emissions.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	0.15 %
Payback:	6.1 Year(s)
Payback Basis:	Reduced fuel consumption.

Background, Justification, and Need:
The existing air preheater baskets are original equipment and are nearing the end of their service lives. The baskets have begun to swell and are difficult to remove for inspection and repairs. Additionally, the old baskets increase pressure drop across the air preheater, which then increases auxiliary load. Poor air preheater heat transfer has reduced boiler efficiency and increased fuel consumption and unit emissions.

Replacing the baskets with like-kind units will result in lower draft losses, reduced auxiliary load, increased boiler efficiency, and lower fuel consumption and unit emissions.

Replacing the baskets will eliminate the immediate possibility of massive air flow blockage due to the degraded cold intermediate baskets.

Capital Project Analysis

Alternatives Reviewed:
Option 1 – Do Nothing
The air preheater baskets are reaching the end of their life. Doing nothing will result in increased pressure drop and lower unit performance. This will increase fuel costs, draft losses, auxiliary load, and the number of unit outages for basket pressure cleaning.

Option 2 – Replace Air Preheater Baskets
Replacing air preheater baskets with new, like-kind equipment will reduce air preheater outlet temperatures, increasing boiler efficiency and lowering fuel consumption and operational costs. Continued use of calcium bromide on the coal to reduce mercury emissions may lead to significantly reduced cold end basket life.

Option 3 – Replace Air Preheater Baskets (enameled)
Replacing air preheater baskets with new, like-kind but enameled equipment will reduce air preheater outlet temperatures both now and through the future. This will also lead to a sustained boiler efficiency and lowered fuel consumption and operational costs. The enameled lower end baskets will hold up to the corrosive environment found when burning coal while treating for mercury removal.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3, replace air preheater baskets, is the recommended option since it is the most cost beneficial to the Cooperative.

Capital Project Analysis

Project Name:	ST2 Feedwater Heater Level Controls
Project Location:	Apache Station
Project Number:	5-00939
Estimated Cost:	$ 78,000 *Including* $ 300 IDC
In Service Month/Year:	11/2015
Anticipated Funding Source:	$ 77,700 RUS Loan Funds
	$ 300 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:

Current level controls on ST2 HP5 and HP6 heaters are pneumatic/mechanical and frequently have problems regulating level control. Engineering recommends upgrading the existing instrumentation to magnetic level gauges and electronic controls. The project will include removal, installation, instrumentation, level controller, valve positioner, and valves. The new instrumentation will allow for better level control and aid in the heater testing process required by FM Global.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	3.A – Work required to maintain equipment at design reliability and efficiency
IRR:	167 %
Payback:	0.6 Year(s)
Payback Basis:	Avoidance of turbine rebuild (1% likelihood) & heat rate penalty for feed water heater out of service (25% likelihood).

Background, Justification, and Need:

ST2 HP5 and HP6 have experienced level control and heater trip problems. This is due to the existing pneumatic/mechanical controls getting stuck during operation. When tubes rupture in the high-pressure feedwater heaters, they tend to have considerable leaks of feedwater into the steam side of the feedwater heater. If the switch fails to work, the dump valve and emergency backflow prevention valve will not actuate. The extraction comes from the cold reheat line so water would enter the high-pressure turbine, which can lead to turbine failure under this sequence of events.

Upgrading level control instrumentation will allow for accurate control and lower maintenance costs. The new level transmitter and switches are magnetic. They are operated by a single magnetic level float inside a level gauge and will lead to much lower maintenance attention. ST3 LP3 feedwater heater is currently equipped with these controls and has been performing well.

Alternatives Reviewed:
Option 1 – Do Nothing
Doing nothing will result in continued poor operational control over the feedwater level in HP5 and HP6.

Option 2 – Install Ultrasonic Level Controls
Ultrasonic level controls will determine the level of the vessels and restore operational control.

Option 3 – Install Magnetic Level Controls
Level controls will restore operational control over the feedwater heaters. Magnetic level controls offer increased performance over current control system at a low cost.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends Option 3 as the most economical and reliable way to restore operational control over the level in the high-pressure feedwater heaters.

Capital Project Analysis

Project Name:	Miscellaneous Piping Replacement 2015
Project Location:	Apache
Project Number:	5-01310
Estimated Cost:	\$ 200,000 *Including* \$ 4,000 IDC
In Service Month/Year:	12/2015
Anticipated Funding Source:	\$ 196,000 RUS Loan Funds
	\$ 4,000 General Funds
	\$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Replace both small and large bore piping that is beyond repair at Apache Station. Piping within budget that is in the worst condition will be replaced first.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	IRR Not Calculated
Payback:	Payback Not Calculated
Payback Basis:	

Background, Justification, and Need:
System piping of units ST2 and ST3 at Apache Station have been experiencing through-wall corrosion problems for many years. The plant Staff has performed numerous leak repairs with external pipe repair clamps. The number of repairs made indicate the need to replace the piping and reduce the maintenance costs of keeping the piping in service. It is easier and less expensive to plan to replace piping than to replace it after it has failed.

Alternatives Reviewed:
Option 1 – Do Nothing
If nothing further is done with piping, it will continue to decay until it leaks again. This will eventually render the piping useless.

Option 2 – Continue the Current Maintenance Approach
The plant Staff has been fixing leaks in piping over and over through the years. This can continue until the piping becomes weakened by the patching and it becomes unsafe to keep in service.

Capital Project Analysis

Option 3 – Replace the Worst of the Piping
This project will not replace all plant piping, only that in the worst condition. Staff believes it is cost effective to begin replacing corroded and failed piping that has become a nuisance because of the need for frequent repair.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff believes Option 3, to begin replacing corroded and failed piping, is the most cost effective.

Capital Project Analysis

Project Name:	ST2/3 CWDF Monitoring Well Relocation
Project Location:	Apache
Project Number:	5-01284
Estimated Cost:	$ 100,000 *Including* $ 558 IDC
In Service Month/Year:	11/2015
Anticipated Funding Source:	$ 99,442 RUS Loan Funds
	$ 558 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Design and install additional Point-of-Compliance (POC) monitoring wells for the Combustion Waste Disposal Facility (CWDF) at Apache Station.

Economics / Justification:

Project Type:	New Construction
Budget Priority Code:	2.A – Legally required work
IRR:	IRR Not Calculated
Payback:	Payback Not Calculated
Payback Basis:	No payback has been calculated for this project.

Background, Justification, and Need:
The aquifer protection permit for the combustion waste disposal facility at Apache Station requires that the facility be monitored for leakage. Monitoring wells are installed down-gradient from the facility in such a manner as to intercept any leakage. These wells are periodically monitored for the presence of indicator constituents. The results of monitoring must show no impact to the underlying aquifer water quality.

Recent studies have indicated that the hydrologic gradient in the vicinity of the CWDF has shifted due to pumping stresses to the aquifer. If these studies are corroborated, the existing POC wells will need to be replaced and oriented to the new gradient.

Alternatives Reviewed:
Option 1 – Do Nothing
Doing nothing may be a feasible option depending on whether the hydraulic gradient has shifted with respect to the CWDF ponds. If, however, the hydraulic gradient changing can be corroborated, then doing nothing will not provide the monitoring Arizona Department of Environmental Quality (AZDEQ) requires.

Option 2 – Relocate the CWDF Monitoring Wells
Assuming the shifting of the hydraulic gradient is corroborated, relocating the CWDF monitoring wells will be necessary to stay in compliance with state operating permits.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends further testing to verify the location of the hydraulic gradient. If the gradient has shifted, Option 2 is the recommended course of action. If the hydraulic gradient has not moved and the monitoring wells are still well positioned, then Staff recommends Option 1.

Capital Project Analysis

Project Name:	ST3 Air Preheater Basket Replacement	
Project Location:	Apache	
Project Number:	5-01294	
Estimated Cost:	$ 1,800,000	*Including* $ 24,000 IDC
In Service Month/Year:	9/2015	
Anticipated Funding Source:	$ 1,776,000	RUS Loan Funds
	$ 24,000	General Funds
	$ 0	Other
RUS Environmental Approval:	Anticipated	
RUS General Funds Approval:	Anticipated	

Recommendation:
The existing air preheater baskets are original equipment and are nearing the end of their service lives. New like-kind baskets will lower fuel consumption and, subsequently, unit emissions.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	18 %
Payback:	5.2 Year(s)
Payback Basis:	17F degree drop in APH outlet temperature equals 0.40% increase in boiler efficiency at 195 MW, 0.9 capacity factor, 8760 hours/yr., heat rate of 10,300 BTU/KWHR, and $2.50/MMBTU.

Background, Justification, and Need:
The existing air preheater baskets are original equipment and are nearing the end of their service lives. The baskets have begun to swell and are difficult to remove for inspection and repairs. Additionally, the old baskets increase pressure drop across the air preheater, which then increases auxiliary load. Poor air preheater heat transfer has reduced boiler efficiency and increased fuel consumption and unit emissions.

Replacing the baskets with like-kind units will result in lower draft losses, reduced auxiliary load, increased boiler efficiency, and lower fuel consumption and unit emissions.

Replacing the baskets will eliminate the immediate possibility of massive air flow blockage due to the degraded cold intermediate baskets.

Alternatives Reviewed:
Option 1 – Do Nothing
The air preheater baskets are reaching the end of their lives. Doing nothing will result in increased pressure drop and lower unit performance. This will increase fuel costs, draft losses, auxiliary load, and the number of unit outages for basket pressure cleaning.

Capital Project Analysis

Option 2 – Replace Air Preheater Baskets (like-kind)
Replacing air preheater baskets with new, like-kind equipment will reduce air preheater outlet temperatures, increasing boiler efficiency and lowering fuel consumption and operational costs.

Option 3 – Replace Air Preheater Baskets (new design)
Replacing air preheater baskets with new designed equipment will reduce air preheater outlet temperatures, increasing boiler efficiency and lowering fuel consumption and operation costs. The newly designed baskets will also be more resistant against ABS pluggage and acid corrosion.

<u>Safety Considerations:</u>
None

<u>Environmental Considerations:</u>
N/A – Categorical Exclusion

<u>Conclusion:</u>
Staff recommends Option 3 as it is the lowest cost alternative while maintaining unit reliability.

Capital Project Analysis

Project Name:	Centac Compressor "B" Rebuild 2015
Project Location:	Apache
Project Number:	5-01303
Estimated Cost:	$ 400,000 *Including* $ 4,000 IDC
In Service Month/Year:	12/2015
Anticipated Funding Source:	$ 396,000 RUS Loan Funds
	$ 4,000 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
The two Centac air compressors provide air for soot blowing and other essential plant air. These two compressors see high duty and fail periodically, which cannot always be predicted. This project is a planning mechanism for a potential Centac compressor failure.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	108 %
Payback:	0.9 Year(s)
Payback Basis:	Avoidance of rental soot blowing air compressors at $36,000 per month.

Background, Justification, and Need:
Plant operation requires the full use of one Centac air compressor. The second of the two compressors is necessary as a backup to the first when it fails. Centac compressor failure could happen at any time. When a compressor fails, its rebuild becomes necessary and urgent. Failure requires contracting with a compressor parts supplier to rebuild the compressor. Labor for the rebuild is performed by AEPCO forces as directed by the parts supplier representative.

Alternatives Reviewed:
Option 1 – Do Nothing
Doing nothing will leave only one compressor in service without essential backup. Should the remaining compressor fail, it would mean significant derate or downtime for both units ST2 and ST3.

Capital Project Analysis

Option 2 – Plan to Use Rental Compressors
Instead of rebuilding the failed compressor, AEPCO could rent backup compressors. Equivalent compressors rent for $36,000 per month plus repair costs and power usage. This option is the most costly.

Option 3 – Centac Compressor Rebuild
Rebuild compressors as they fail to restore essential air compressor redundancy. A compressor rebuild has a cost payback of less than one year based on Option 2 costs.

<u>Safety Considerations:</u>
None

<u>Environmental Considerations:</u>
N/A – Categorical Exclusion

<u>Conclusion:</u>
Option 3, the Centac compressor rebuild, is the preferred option. When a rebuild becomes necessary, the restoration of air compressor redundancy will protect from a major loss of generation.

Capital Project Analysis

Project Name:	ST2 ID Fan Speed Circuit Upgrade
Project Location:	Apache
Project Number:	5-01304
Estimated Cost:	$ 36,000 *Including* $ 600 IDC
In Service Month/Year:	5/2015
Anticipated Funding Source:	$ 35,400 RUS Loan Funds
	$ 600 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Upgrade the speed circuit that controls the ST2 ID fan speed.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	136 %
Payback:	0.7 Year(s)
Payback Basis:	Saving of 1 boiler trip per year. Replacement power @ $50/MWh for 6 hours.

Background, Justification, and Need:
ST2 has two induced draft (ID) fans that pull (induce) the combustion gases from the boiler and push them out the stack. The ID fans are set up to run on two different speeds: fast and slow. The different speeds allow the unit to run at different loads more efficiently.

The circuits that control the speed changes consist of multiple mechanical relays. These different relays have, in the past, proved to be only semi-reliable. Occasionally when making the speed change the ID fan will trip. These trips, while infrequent, cause the operators to shy away from making the changes necessary for the load of the unit. The operators will opt to keep the fans running on high and throttle them back with the use of dampers, causing extra wear on the dampers and higher amps on the motors.

When ST2 switches to natural gas fuel, the forecast is for this unit to perform many load changes and run at lower loads more often. When running at lower loads and when varying the load, the speed of the ID fans becomes more critical than when just running close to full load. By upgrading the speed control circuits on the fans, the reliability of the switch will be restored. One the fan can switch between high and low speeds reliably, the operators will regulate the speeds of the fan for the load of the unit.

Alternatives Reviewed:
Option 1 – Do Nothing
Doing nothing will leave the speed control circuits in the same condition they are. The ID fans will be kept in a "high" mode and will use excess amps at periods of low loads.

Option 2 – Upgrade the ID Fan Inlet Dampers
By upgrading the ID fan inlet dampers, the wear issues from throttling the ID fan will be minimized. However, the fan will still be drawing more amps than are required.

Option 3 – Upgrade the ID Fan Speed Control Circuit
By upgrading the speed control circuit, the ID fans will be able to switch from high to low speed without increased risk of tripping off the fan.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends Option 3 as the most economical method to restore unit reliability.

Capital Project Analysis

Project Name:	ST2 Mercury Control	
Project Location:	Apache	
Project Number:	5-01308	
Estimated Cost:	$ 1,300,000	*Including* $ 30,000 IDC
In Service Month/Year:	11/2015	
Anticipated Funding Source:	$ 1,270,000	RUS Loan Funds
	$ 20,000	General Funds
	$ 0	Other
RUS Environmental Approval:	Anticipated	
RUS General Funds Approval:	Anticipated	

Recommendation:
Install an activated carbon injection (ACI) system on ST2 to aid in the oxidation and removal of mercury from the flue gas.

Economics / Justification:

Project Type:	New Construction
Budget Priority Code:	4.B – Code, government regulations, etc.
IRR:	1677 %
Payback:	0.1 Year(s)
Payback Basis:	Based on $2.00/MMBtu differential in fuel prices for ST2 to burn coal from April 2016 to Dec 2017. Heat rate of 10,700, CF = 0.70.

Background, Justification, and Need:
The (EPA issued a standard to regulate the amount of mercury emissions from a power plant. This rule, known as the MATS, becomes effective in April 2015 unless a utility applies for and is granted a one-year extension. According to MATS, the mercury emission standard is 1.2 pounds of mercury for every trillion Btu burned in the boiler for sub-bituminous coal. Apache Station fires sub-bituminous coal and is therefore going to be held to the MATS limit of 1.2 lbs./TBtu.

In November 2013, Apache Station applied for the one-year extension. This extension was granted in December 2013. Starting in April 2016, all units at Apache Station will need to emit less than 1.2 pounds of mercury for every trillion Btu burned. Currently the mercury emissions of ST2 are in the 3 to 5 lbs./TBtu range. Calcium bromide has been added to the coal as it is elevated up to the bunkers since 2010 to aid in the oxidation and therefore removal of mercury. This oxidizer does a good job aiding in the removal of mercury from the system, but it alone will not allow ST2 to achieve the mercury limits.

Capital Project Analysis

In May 2014 testing was performed with different activated carbons by injecting them into the flue gas ducts to determine if this technology would enable ST2 to achieve the emissions limits. The testing found that neither calcium bromide nor activated carbon injection alone would achieve the emission target of 1.2 lbs./TBtu. When both technologies were used simultaneously, however, the emissions limits were achieved. If ST2 is to keep burning coal past the MATS deadline of April 2016, a different mercury control technology must be employed to achieve the standard. By installing an ACI system to work in conjunction with the existing CaBr2 system, compliance is obtainable.

Alternatives Reviewed:

Option 1 – Do Nothing

Doing nothing will allow ST3 to burn coal up until the MATS deadline takes effect (April 2016). After the MATS deadline, the unit will need to switch fuel from coal to natural gas in order to be compliant with the new emissions standard.

Option 2 – Install Gore Mercury Modules in the Top of the Scrubber

This option employs relatively new technology from W.L. Gore & Associates called mercury modules. These mercury modules are a passive technology that have a semi-permeable membrane, a deriving of Polytetrafluoroethylene (PTFE), which reacts with the mercury in the flue gas to absorb mercury. Once the mercury is absorbed by the modules, the flue gas passes through the modules and is emitted less the mercury. The mercury modules continue to collect the mercury until they reach their service life and have to be disposed of and replaced.

Option 3 – Install Mercury Oxidation Catalyst

This option requires the installation of a catalyst that works very similar to a Selective Catalytic Reduction (SCR). The ductwork is enlarged at a convenient location and mercury oxidizing catalysts are installed to react with the mercury in the flue gas. The catalyst aids to oxidize the mercury in the flue gas so that it can be collected in the scrubber towers for removal. The mercury catalyst will then need replacing at specified intervals as it degrades over its useful life.

Option 4 – Switch Fuel from Coal to Natural Gas

This option would not require any additional mercury removal equipment as natural gas emissions do not contain any mercury. However, this would yield a more expensive operation than removing mercury from the coal combustion process.

Option 5 – Install Activated Carbon Injection

This option employs an active system that can be adjusted up or down to change the mercury oxidation and removal required for the different types of coal to stay within the EPA emission limits. Powdered activated carbon is injected into the flue gas ducts. The brominated carbon reacts with the mercury to oxidize and capture it. Once captured it is collected in the wet absorber towers and removed with the waste slurry.

Safety Considerations:

None

Capital Project Analysis

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends Option 5 as it is the lowest cost known operational solution.

Capital Project Analysis

Project Name:	Apache Cathodic Protection Upgrade	
Project Location:	Apache	
Project Number:	5-01309	
Estimated Cost:	$ 136,000	*Including* $ 2,700 IDC
In Service Month/Year:	12/2015	
Anticipated Funding Source:	$ 133,300	RUS Loan Funds
	$ 2,700	General Funds
	$ 0	Other
RUS Environmental Approval:	Anticipated	
RUS General Funds Approval:	Not Required	

Recommendation:

The cathodic protection system for the underground piping for natural gas, water, air, and electrical conduits at Apache Station should be restored to its fully functioning and protecting state.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	34 %
Payback:	2.9 Year(s)
Payback Basis:	Loss of generation and repair and maintenance cost.

Background, Justification, and Need:

Underground piping systems have a tendency to corrode due to the difference in electric potential of the pipe and the surrounding soils. This corrosion will eventually cause the piping systems to rupture and leak, which can be costly to repair. One way to prevent the corrosion of underground piping is to install cathodic protection, which provides sacrificial cathode and anode components. These components will corrode and degrade but will spare structures they protect of any corrosion.

Once the sacrificial components are gone, the protection the cathodic system offered has been used up and the underground piping will once again start to corrode. By replacing the consumables of the cathodic protection system, the underground piping will once again be protected from any electric potential differences. This project aims to replace the consumables of the cathodic protection system and restore the protection of the underground natural gas, water, and air piping and electrical conduit at Apache Station.

Capital Project Analysis

Alternatives Reviewed:
Option 1 – Do Nothing
As the cathode and anode bed degrades, the cathodic protection for the underground piping will become less and less effective. Once the cathodic protection quits functioning, the underground piping will start to corrode and will need replacement in the future.

Option 2 – Replace Cathodic Protection System
Cathodic protection systems are designed to degrade over time as the sacrificial parts are used up in favor of the piping they protect. The cathodic protection system can be replaced to restore the full functionality of piping protection.

Option 3 – Repair Cathodic Protection System
By replacing the sacrificial components of the cathodic protection system, the underground piping protection will be restored. Once cathodic protection has been restored, the corrosion of the underground piping will be delayed until the system fails.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends Option 3 because it will restore the cathodic protection system for the underground piping at the lowest cost.

Capital Project Analysis

Project Name:	ST2 Generator Bushing Replacement
Project Location:	Apache
Project Number:	5-01320
Estimated Cost:	$ 122,000 *Including* $ 750 IDC
In Service Month/Year:	5/2015
Anticipated Funding Source:	$ 121,250 RUS Loan Funds
	$ 750 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Replace the faulty generator bushings.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	225 %
Payback:	0.4 Year(s)
Payback Basis:	Reduced risk of outage.

Background, Justification, and Need:
ST2 generator has six gas-cooled high-voltage bushings (three line side and three neutral side). The bushing consists of a tubular copper conductor assembled in a porcelain bushing. Generator stator winding connects at bottom of the bushing and high-voltage buss bar connects top side of the bushings.

A minor asphalt leak from neutral side middle bushing was found during the generator inspection during the March 2012 overhaul. The bushing was re-inspected in May 2013 and it was observed that the asphalt continues to leak out slowly.

Cause of the asphalt leak can be failure of a bottom seal or bushing getting hot from blocked ventilation. The asphalt is a backup sealing compound and the asphalt leak may lead to hydrogen leaks. It is recommended to monitor the hydrogen consumption to see if there is any abnormal loss and replace the bushing during the next opportunity.

Capital Project Analysis

<u>Alternatives Reviewed:</u>

Option 1 – Do Nothing

The asphalt leak may lead to a hydrogen leak. The generator is designed to run at 33 psig H_2 pressure to produce 240,000 kVA. Thus, the decrease in hydrogen pressure will lead to generator capacity reduction. Minimum operating H_2 pressure is 5 psig, at which the maximum generator capability is 192,000 kVA.

Option 2 – Repair the Faulty Bushing

Repair of the bushing requires removal and sending it out for repair. The repair is estimated to take two to three weeks and then it could be sent back for installation. The total cost of the repair is equal to the total cost of the replacement bushing.

Option 3 – Replace the Faulty Bushing

This option will avoid any risk of hydrogen leak that could lead to reduced output and forced outage. This bushing would be replaced at the next scheduled unit overhaul.

<u>Safety Considerations:</u>

None

<u>Environmental Considerations:</u>

N/A – Categorical Exclusion

<u>Conclusion:</u>

Option 3 is the recommended option to avoid any risk of hydrogen leak, minimized generator output reduction, and forced outage.

Capital Project Analysis

Project Name:	GT4 Stage 1 HPC Replacement
Project Location:	Apache Station
Project Number:	5-01210
Estimated Cost:	$ 128,000 *Including* $ 800 IDC
In Service Month/Year:	11/2016
Anticipated Funding Source:	$ 127,200 RUS Loan Funds
	$ 800 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Replace the GT4 LM-6000 Stage 1 High-Pressure Compressor (HPC) blades at 16,000 operating hours as normal routine maintenance.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	2.F – Managerial and/or Board discretion
IRR:	64 %
Payback:	1.5 Year(s)
Payback Basis:	Payback is 1 in 50 chance of $3M cost of repair to exceeding 16,000 hours.

Background, Justification, and Need:
The Original Equipment Manufacturer (OEM) recommends that the Stage 1 HPC blades be replaced at 16,000 operating hours as normal routine maintenance. Staff expects that GT4 will approach 16,000 operating hours during the 2014 capital planning year.

Alternatives Reviewed:
Option 1 – Do Nothing
Risk the consequences of performance degradation due to worn out compressor blades. Also risk the safety and integrity of the unit due to failure of worn Stage 1 blades.

Option 2 – Repair
Repair of the compressor blades is essentially what is being performed. A rotable set (rebuilt) will be swapped out with the original blades. The originals will be repaired by OEM or third party and reinstalled in another unit.

Capital Project Analysis

Option 3 – Replace Stage 1 Blades as Recommended
Replace the Stage 1 HPC blades and maintain performance and reliability of the gas turbine. This is the prudent recommendation of the OEM and other industry sources.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3 is the preferred option. Replacement of the Stage 1 HPC blades will maintain performance and reliability of the gas turbine and will enable it to operate as designed.

Capital Project Analysis

Project Name:	ST1 Low NOx Burners	
Project Location:	Apache Station	
Project Number:	5-01242	
Estimated Cost:	$ 2,500,000	*Including* $ 31,000 IDC
In Service Month/Year:	11/2016	
Anticipated Funding Source:	$ 2,469,000	RUS Loan Funds
	$ 31,000	General Funds
	$ 0	Other
RUS Environmental Approval:	Anticipated	
RUS General Funds Approval:	Anticipated	

Recommendation:
Install a new low NOx gas burner system and gas recirculation equipment and ductwork on unit ST1. The purpose of the project is to reduce the level of nitrogen oxides in the exhaust flue gas of unit ST1.

Economics / Justification:

Project Type:	New Construction
Budget Priority Code:	2.A – Legally required work
IRR:	IRR Not Calculated
Payback:	Payback Not Calculated
Payback Basis:	

Background, Justification, and Need:
ST1 is a 75 MW gas-fired, seasonal-peaking unit at Apache Station that was placed in service in 1963. In 2007, AEPCO performed a "Best Available Retrofit Technology" (BART) analysis in accordance with the recommendations of the Arizona Department of Environmental Quality (ADEQ). This low NOx burner installation project is the BART-recommended solution for NOx emissions.

Both the federal EPA and the State of Arizona will require AEPCO to implement its BART recommendations and be in compliance with a 0.056 lbs. NOx/MMBTU by December 5, 2017.

Alternatives Reviewed:
Option 1 – Do Nothing
If the chosen course of action was to do nothing, AEPCO would likely lose its operating permit and/or pay substantial fines. The base ST1 NOx emission is approximately 0.3 lbs. NOx per MMBtu.

Capital Project Analysis

Option 2 – Plan for a Selective Catalytic Reduction (SCR) Project
This highest-cost option suggested as part of the BART analysis includes the installation of low-NOx burners and an SCR. The project has a total estimated capital cost of $32,000,000. The resulting NOx emission is estimated at 0.07 lbs. NOx per MMBtu.

Option 3 – Plan for a Low-NOx Burner with FGR Project
This project is the BART-recommended project and has an estimated cost of $2,052,000. This project is estimated to cut current NOx emissions in half to approximately 0.056 lbs. NOx per MMBtu.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3 is the recommended option to reduce the NOx emissions on ST1 by an economical and effective solution.

Capital Project Analysis

Project Name:	RO Sump Restoration
Project Location:	Apache
Project Number:	5-01272
Estimated Cost:	$ 100,000 *Including* $ 1,000 IDC
In Service Month/Year:	11/2016
Anticipated Funding Source:	$ 99,000 RUS Loan Funds
	$ 1,000 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Backfill the RO sump with concrete to eliminate the structural risks to the RO building.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	IRR Not Calculated
Payback:	Payback Not Calculated
Payback Basis:	No payback has been calculated for this project.

Background, Justification, and Need:
The mixed bed demineralizers use both acid and caustic solutions for treatment of make-up water for ST2 and ST3. The acid and caustic tanks have a spillage collection basin that drains down into a sump under the southeast corner of the building. The underground sump was constructed with concrete walls to collect any chemical spills. Over time the chemicals have reacted with the lime in the concrete forming the basin to the point the lime has been removed from the concrete. The lower concrete wall around the sump has been removed, leaving a pile of small rock (aggregate) in its place.

As the concrete was being chemically attacked and dissolved, the rebar within the concrete walls also rusted and corroded to the point it is now missing. The missing portion of the wall has raised some concern over the structural integrity of some concrete caisson in the area that supports the ST2 DA tank on the 5th floor. Some investigations in the sump have revealed the acid corrosion is limited to 1 to 2 inches of soil beyond the concrete sump wall. The concrete caisson seems unaffected by the chemical corrosion.

The location of the Reverse Osmosis (RO) sump under the corner of the building was convenient when installed, but now the acid and caustic tanks are no longer used for chemical treatment of the make-up water. The structural damage to the concrete sump needs to be remedied to ensure the structural integrity of the building above it.

Alternatives Reviewed:

Option 1 – Do Nothing

Doing nothing will leave the walls of the RO sump in the same condition they are presently in. Although the chemicals that dissolved the concrete are no longer used, the structural issues leave the building at risk of failure.

Option 2 – Repair Sump Walls

Repairing the sump walls will restore the RO sump back to operation and restore the structural integrity of the RO building.

Option – Backfill Sump with Concrete

Backfilling the sump with concrete will be a fast and economical way to fix the structural integrity of the RO building. This method would remove the sump from the building and remove the ability to put the chemical treatment process back into service at a later time.

Safety Considerations:

Work area is underground in a confined space.

Environmental Considerations:

N/A – Categorical Exclusion

Conclusion:

Staff recommends Option 3 as the most economical means to repair the structural risk to the RO building.

Capital Project Analysis

Project Name:	ST2 Nitrogen Blanket System Install
Project Location:	Apache
Project Number:	5-01302
Estimated Cost:	$ 136,000 *Including* $ 3,600 IDC
In Service Month/Year:	12/2016
Anticipated Funding Source:	$ 132,400 RUS Loan Funds
	$ 3,600 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Recommend that a nitrogen blanket system be installed on Unit 2 boiler for proper layup during the winter months. This option will mitigate boiler tube corrosion and extend the service life of the unit.

Economics / Justification:

Project Type:	New Construction
Budget Priority Code:	3.A – Work required to maintain equipment at design reliability and efficiency
IRR:	462 %
Payback:	0.2 Year(s)
Payback Basis:	Based on current N2 consumption of $100,000 every 2 mos. on ST1.

Background, Justification, and Need:
Unit 2 is scheduled to be converted to natural gas by 2017. When that happens, there is the possibility that Unit 2 may be utilized as a peaking unit due to the high cost of fuel. If the decision is made to lay up the unit during the winter months, then it would be prudent to integrate a nitrogen blanket system on the boiler to mitigate boiler tube corrosion/degradation due to oxidation.

Alternatives Reviewed:
Option 1 – Do Nothing
Risk boiler tube corrosion/degradation due to oxidation. This option will increase the likelihood of boiler tube leaks in the future and decrease the overall service life of the boiler.

Option 2 – Integrate Nitrogen Blanket System
Modify ST2 boiler piping vents, including HP heaters, so that a nitrogen blanket system can be implemented for temporary layup during the winter months. This is the preferred option. This

option will preserve the integrity of the boiler tubes and increase the overall service life of the boiler.

Safety Considerations:
Nitrogen handling, welding on the boiler vent lines.

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 2 is the preferred option. This option will minimize boiler tube corrosion, preserve the integrity of the boiler tubes during non-operation, and increase the overall service life of the boiler.

Capital Project Analysis

Project Name:	Miscellaneous Cable Replacement
Project Location:	Apache
Project Number:	5-01305
Estimated Cost:	$ 114,000 *Including* $ 3,300 IDC
In Service Month/Year:	12/2016
Anticipated Funding Source:	$ 110,700 RUS Loan Funds
	$ 3,300 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Monitor and replace power cables with deteriorated insulation before it fails, as power cable failure can cause equipment (motor and transformer) damage and unit outage.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	65 %
Payback:	1.5 Year(s)
Payback Basis:	Loss of generation and repair and maintenance cost.

Background, Justification, and Need:
For the last few years, power cables have been failing and we believe aging is the main factor. Power cable failure leads to reduction in unit power generation and, in some cases, unit outage. Additionally, power cable failure can cause damage to the equipment (motor and transformer) connected to it. Therefore, power cables need to be tested on a routine basis and replaced if they are degrading to minimize unit outage and maintenance cost.

Alternatives Reviewed:
Option 1 – Do Nothing
As the power cables are aging and their insulations are deteriorating, cables with deteriorated insulation will eventually fail. Power cable failure will lead to partial or full unit outage and can cause damage to the motor/transformer, incurring higher maintenance costs.

Option 2 – Monitor and Replace Power Cables with Degraded Insulation Before It Fails.
Risk of damaging equipment connected to the power cable will be avoided. Replacement work can be planned to minimize unit outage.

Capital Project Analysis

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends Option 2, to approve a miscellaneous cable project, to maintain reliability.

Capital Project Analysis

Project Name:	GT2 Controls Upgrade
Project Location:	Apache
Project Number:	5-01306
Estimated Cost:	$ 350,000 *Including* $ 10,000 IDC
In Service Month/Year:	12/2016
Anticipated Funding Source:	$ 340,000 RUS Loan Funds
	$ 10,000 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Upgrade the GT2 controls.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	9 %
Payback:	8 Year(s)
Payback Basis:	Based on losing non-spinning reserve capacity when other units are at full load.

Background, Justification, and Need:
The controls system on GT2 provided by General Electric (GE) in the 1990s is no longer being supported by the manufacturer. In fact, the manufacturer ended their support of this control system in 2012. In 2014, GE notified users of the control system and informed them they will no longer be producing any spare parts for the obsolete system.

The control system is the interface by which the unit is operated. If a failure in one of the components in the controls system fails, the gas turbine will be unavailable until such time the control system is replaced or a spare part is located and installed.

Alternatives Reviewed:
Option 1 – Do Nothing
By doing nothing, GT2 will continue to operate in the same manner it operates now. The unit will be available as long as nothing in the control system fails. If a failure of any control system component occurs, the gas turbine will be unavailable until the controls system is replaced.

Option 2 – Search for a Similar Used Control System for Spare Parts
If a used GE control system similar to the one currently installed on GT2 can be located and procured, GT2 can continue to operate until such time that all spares fail and cannot be sourced. As the spare parts for this system are no longer produced, finding a similar spare will prove problematic and only postpones the control system replacement.

Option 3 – Upgrade GT2 Control System
Upgrading the control system on GT2 will put a system in service that is supported by the manufacturer. A currently produced control system will also have readily available spare parts should the need arise.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends Option 3 as the best course to ensure unit availability.

Capital Project Analysis

Project Name:	Grinnell Fire System Upgrades
Project Location:	Apache
Project Number:	5-01307
Estimated Cost:	$ 60,000 *Including* $ 2,300 IDC
In Service Month/Year:	12/2016
Anticipated Funding Source:	$ 57,700 RUS Loan Funds
	$ 2,300 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Replace both ST2 and ST3 fire system valves. Recommend taking a closer look at replacing ST1 valves due to payback.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	42 %
Payback:	2.4 Year(s)
Payback Basis:	Based on 3-day outage of replacement power at $40/mwh and 5% probability.

Background, Justification, and Need:
American Fire has recommended upgrading several Grinnell valves due to the unavailability and obsolescence of replacement parts. Installation of replacement valves and associated trim will require a retrofit of the supply piping as it is not a "like kind" replacement.

Alternatives Reviewed:
Option 1 – Do Nothing
This option risks the possibility of having a valve fail during the event of a fire and burning down a cooling tower. This option costs nothing but has the greatest amount of risk.

Option 2 – Repair with Replacement Parts
This option is the most economical but carries some risk. Replacement parts are not always available and the equipment could be at risk if a valve were to fail during a fire. Repair costs are estimated to be half the cost of replacing the valve.

Capital Project Analysis

Option 3 – Replace All Valves
This is the most expensive option but offers the least amount of risk. The total cost of replacing all the valves is around $143,000.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3 is the recommended option. Replacement of the fire system valves will provide the least amount of risk given an expected plant retirement date of 2035. Further review on a unit-by-unit basis is still recommended since future load forecasts can vary between units and will ultimately impact payback.

Capital Project Analysis

Project Name:	ST2 .085 NOx Compliance Upgrades	
Project Location:	Apache	
Project Number:	5-01275	
Estimated Cost:	\$ 7,000,000	*Including* \$ 132,360 IDC
In Service Month/Year:	11/2017	
Anticipated Funding Source:	\$ 6,867,640	RUS Loan Funds
	\$ 132,360	General Funds
	\$ 0	Other
RUS Environmental Approval:	Anticipated	
RUS General Funds Approval:	Anticipated	
RUS General Funds Approval:	Not Required	

Recommendation:
It is recommended to install a low NOx upgrade on ST2 to comply with an ADEQ/EPA nitrogen oxide emission limit of 0.085 lbs./MMBtu.

Economics / Justification:

Project Type:	New Construction
Budget Priority Code:	2.A – Legally required work
IRR:	IRR Not Calculated
Payback:	Payback Not Calculated
Payback Basis:	No payback has been calculated as this project is mandated for compliance under the EPA SIP/FIP for regional haze.

Background, Justification, and Need:
ST2 current nitrogen oxide (NOx) emission limit is 0.8 lbs./MMBtu. The ADEQ/EPA SIP/FIP will lower the ST2 NOx limit to 0.085 lbs./MMBtu while burning pipeline natural gas. Extensive planning has shown that switching ST2 to pipeline natural gas with the required emission controls will be the lowest cost peaking resource for AEPCO post-2017.

Alternatives Reviewed:
Option 1 – Do Nothing
This option will require ST2 to be idled on December 5, 2017 as the unit will not meet required NOx limits after that date.

Option 2 – Install Selective Catalytic Reduction (SCR)
This option would install ammonia injection with a catalyst, and similar modifications for burners and ductwork as in Option 3 below, to control NOX emissions. Costs for an SCR catalyst are prohibitively expensive and will reduce emission levels below what is required by ADEQ/EPA.

Capital Project Analysis

Option 3 – Fuel Switch to Natural Gas and Install Low NOx upgrades
This option installs a new, larger flue gas recirculation fan, motor, and variable frequency drive to reduce oxygen at the gas burners, low nitrous oxide burners, additional over-fire air, ductwork, and additional controls to the secondary air systems. This low NOx upgrade will optimize the capital and O&M costs of NOx compliance. The system will require modifications to ductwork with minor modifications for boiler pressure parts.

Safety Considerations:
Modifications to the controls, burners, dampers, and ductwork must consider NFPA standards for safety.

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3, install low NOx upgrades, is the most economical solution for nitrogen oxide compliance and is recommended by Engineering.

Capital Project Analysis

Project Name:	ST3 HP Feed Water Heaters Level Control
Project Location:	Apache
Project Number:	5-01135
Estimated Cost:	$ 96,000 *Including* $ 900 IDC
In Service Month/Year:	4/2017
Anticipated Funding Source:	$ 95,100 RUS Loan Funds
	$ 900 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Current level controls on ST2 HP5 and HP6 heaters are pneumatic/mechanical and frequently have problems regulating level control. Engineering recommends upgrading the existing instrumentation to magnetic level gauges and electronic controls. The project will include removal, installation, instrumentation, level controller, valve positioner, and valves. The new instrumentation will allow for better level control and aid in the heater testing process required by FM Global.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	3.A – Work required to maintain equipment at design reliability and efficiency
IRR:	42 %
Payback:	2.4 Year(s)
Payback Basis:	Avoidance of turbine rebuild (0.1% likelihood) and heat rate penalty for feedwater heater out of service (25% likelihood).

Background, Justification, and Need:
ST2 HP5 and HP6 have experienced level control and heater trip problems. This is due to the existing pneumatic/mechanical controls getting stuck during operation. Level float switches fail to operate for this reason, which can lead to turbine failure.

Upgrading level control instrumentation will allow for accurate control and minimal failures. The level transmitter and switches are magnetic. They are operated by a single magnetic level float inside a level gauge. ST3 LP3 feedwater heater is currently equipped with these controls and has been performing well.

Capital Project Analysis

Alternatives Reviewed:
Option 1 – Do Nothing
Doing nothing will result in continued poor operational control over the feedwater level in HP5 and HP6.

Option 2 – Install Ultrasonic Level Controls
Ultrasonic level controls will determine the level of the vessels and restore operational control.

Option 3 – Install Magnetic Level Controls
Level controls will restore operational control over the feedwater heaters. Magnetic level controls offer increased performance over the current control system at a low cost.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends Option 3 as the most economical and reliable way to restore operational control over the level in the high-pressure feedwater heaters.

Capital Project Analysis

Project Name:	ST3 Classifier Replacement
Project Location:	Apache Station
Project Number:	5-00921
Estimated Cost:	$ 1,345,000 *Including* $ 14,600 IDC
In Service Month/Year:	4/2017
Anticipated Funding Source:	$ 1,330,400 RUS Loan Funds
	$ 14,600 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Anticipated

Recommendation:
Replace the six static pulverized coal classifiers of unit ST3 with new classifiers of similar design. The new classifiers will have installed ceramic tiles to extend the required maintenance intervals.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	3.B – Economic Justification
IRR:	65 %
Payback:	1.6 Year(s)
Payback Basis:	Based on lost generation for five days to repair a classifier.

Background, Justification, and Need:
Each of the coal units have three ball mills (pulverizers) to crush coal to a fine powder. Each mill has two classifiers that allow only fine coal to move to the boiler, where it is ignited. All of this equipment is required to operate at full load. The ST3 ball mill classifiers see a heavy erosive atmosphere of coal particles and air. Over time, abrasion to the interior of the classifiers causes serious damage to the base metal. After many years of repair cycles, it becomes necessary to replace the entire classifier. Continued use of over-repaired classifiers may bring a serious failure that will require taking a mill out of service to repair the damage. The existing classifiers are at the point where they need to be replaced.

The classifiers have been replaced once before. The classifiers in this second set have essentially reached the end of their lives. The classifiers are pieces of equipment required to maintain optimum coal fineness, low NOx emissions, lower fuel costs, boiler efficiency, and low carbon levels in the fly ash for continued ash sales.

Capital Project Analysis

<u>Alternatives Reviewed:</u>
Option 1 – Do Nothing
This option will continue to use the existing classifiers, resulting in continuously increasing repair costs as the steel shell is eroded and plates are welded in to stop the coal leaks. Unit deratings equivalent to one pulverizer will be required to complete frequent repairs. The coal dust leaks are also a safety hazard.

Option 2 – Swap ST2 and ST3 Classifiers
This option will take the new (2011) classifiers from ST2, exchange them with the classifiers on ST3. When ST2 switches to natural gas, the classifiers will be sitting idle. This option would utilize the newer equipment, but will cost as much in labor as replacing the ST3 classifiers.

Option 3 – Replace the Classifiers
This option will be a like-kind replacement of the existing ceramic-lined classifiers, which are expected to have a service life of 15 years. This option will reduce maintenance costs, eliminate generation losses due to pulverizer outages for classifier repairs, and greatly increase safety due to coal dust reductions around the classifiers.

<u>Safety Considerations:</u>
Coal classifier leaks cause unsafe coal dust accumulations. Replacement will eliminate the hazard at the classifiers.

<u>Environmental Considerations:</u>
N/A – Categorical Exclusion

<u>Conclusion:</u>
Option 3, classifier replacement, is the preferred option and the prudent business plan choice.

Capital Project Analysis

Project Name:	ST3 Condenser Air Removal Re-tube
Project Location:	Apache
Project Number:	5-01170
Estimated Cost:	$ 491,000 *Including* $ 8,750 IDC
In Service Month/Year:	5/2017
Anticipated Funding Source:	$ 482,250 RUS Loan Funds
	$ 8,750 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
The air removal section of the condenser is exposed to corrosion. Numerous tubes in this section have been plugged. Engineering recommends that the air removal section of the condenser have further tube plugging or be replaced. These two options will result in reduced unit derations and unit outages will occur.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	6 %
Payback:	9.7 Year(s)
Payback Basis:	The payback is based on a tube leak and a unit deration of 100MW for one week at $30/MWh once per year. 10% likelihood (this has already happened on ST2).

Background, Justification, and Need:
The air removal section of the condenser is seeing corrosion due to steam impingement and oxidation. All other tubes from a Conco ECT report indicate that the other tubes are in good condition. The air removal section is approximately 450 tubes. Further tube plugging or replacement of this section would reduce unit deratings.

Alternatives Reviewed:
Option 1 – Do Nothing
Continue to operate in current condition. Recent testing reports on the air removal section indicate wall thinning on some tubes. Reduction in power and forced outages may occur.

Capital Project Analysis

Option 2 – Further Plug Thinning Tubes in the Air Removal Section
Perform additional tube eddy-current testing to determine which tubes require plugging. Remove tube samples from the unit to determine the root cause of tube thinning. This will increase unit reliability with a minimal amount of expenditure.

Option 3 – Replace Tubes with In-kind Material
Replace the existing air removal condenser tubes with in-kind 90/10 copper/nickel tubes. This will increase unit reliability by decreasing unit deratings from the already deteriorated air removal section.

Option 4 – Replace Tubes with Improved Stainless Steel
Replace the existing air removal condenser tubes with improved alloy material tubes. This will increase unit reliability by decreasing unit deratings from the already deteriorated air removal section.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 4, replace the condenser air removal section tubes with improved alloy material, is the preferred option and is recommended by Engineering as the most economical solution.

Capital Project Analysis

Project Name:	ST3 Yokogawa Replacement
Project Location:	Apache Station
Project Number:	5-01220
Estimated Cost:	$ 67,500 *Including* $ 700 IDC
In Service Month/Year:	11/2017
Anticipated Funding Source:	$ 66,800 RUS Loan Funds
	$ 700 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Replace the existing, obsolete, 15 year-old Yokogawa data acquisition and alarming hardware on unit ST3. This project will also include the labor to remove redundant data points where applicable.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	3.B – Economic Justification
IRR:	385 %
Payback:	0.1 Year(s)
Payback Basis:	Based on 2-week outage to replace due to system failure.

Background, Justification, and Need:
The Apache Station control room originally had a number of data strip-chart recorders installed. This required the continual storage of rolls of paper with actual operating data (temperatures, pressures, etc.). Approximately 15 years ago, these strip-chart recorders were replaced by data acquisition hardware that stored the data digitally. This was very beneficial because old data could now be trended and analyzed to assist with troubleshooting upset conditions of the units.

The data acquisition systems installed 15 years ago are now obsolete and no longer supported with spare parts or technical assistance by the manufacturer. A limited number of spare parts are maintained in AEPCO's warehouse. As these spares become depleted, they cannot be readily replaced. If a component fails without spares on hand, critical data will be unavailable to the operators for an extended period of time.

This project will upgrade the data acquisition hardware including the labor to disconnect the input wiring and reconnect it to the new hardware.

Capital Project Analysis

Alternatives Reviewed:
Option 1 – Do Nothing
If nothing is done, the existing data acquisition hardware will continue to operate until a system component fails. Any failure might mean that the hardware becomes inoperable and will limit the data available to the operators for normal operation. This information is used to analyze system and equipment operation and is essential to troubleshooting operating and equipment problems. If this system becomes unavailable, it will not immediately affect the normal operation of the plant. However, it will increase the risk that equipment or system failures are not predicted in a timely fashion to avoid unit outages. Loss of this data will also severely hamper troubleshooting and root-cause failure analysis.

Option 2 – Replace the Existing Yokogawa Hardware
This project will replace the existing ST3 Yokogawa data acquisition system and assure continued, reliable data acquisition for ST3. This replacement will enable Staff to operate and maintain ST3 with the information deemed necessary to keep the unit at design levels of reliability and availability.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 2, replacement of the existing Yokogawa hardware, will assure that important operating data can continue to be viewed by the operators, stored for future use, and analyzed by Engineering. Option 2 is the recommended alternative.

Capital Project Analysis

Project Name:	ST3 SDAS Mist Eliminator Upgrade
Project Location:	Apache Station
Project Number:	5-01229
Estimated Cost:	$ 400,000 *Including* $ 6,083 IDC
In Service Month/Year:	5/2017
Anticipated Funding Source:	$ 393,317 RUS Loan Funds
	$ 6,083 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
The existing stainless steel Mist Eliminator (ME) packing in the scrubber towers has become etched by acid gases, and damage from repeated cleanings has reduced its performance. It is recommended that newer design, tighter-spaced mist eliminator packing be installed to reduce stack moisture and ME packing cleaning time.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	2.A – Legally required work
IRR:	IRR Not Calculated
Payback:	27 Year(s)
Payback Basis:	Reduced stack moisture and ME packing cleaning time.

Background, Justification, and Need:
Wide-spaced mist eliminator packing was installed several years ago to reduce plugging of the original style mist eliminator packing. This both reduced moisture levels and extended the time between packing cleanings. However, acid gases have slowly etched the stainless steel and repeated cleanings have damaged the packing, reducing its efficiency.

Newer designs in shape, spacing, and materials for mist eliminator packing have resulted in superior moisture removal efficiencies. Installation of this upgraded packing will reduce stack flue gas moisture levels and ME packing cleaning time.

Alternatives Reviewed:
Option 1 – Do Nothing
The existing stainless steel mist eliminator packing has become etched by acid gases, and is becoming damaged from repeated cleanings. Stack moisture levels have risen since initial installation. This may result in opacity violations.

Capital Project Analysis

Option 2 – Replace the Mist Eliminator with Like-Kind
This option would replace the mist eliminators with like-kind design and material. This would slightly reduce the moisture levels in the stack and remove any issues caused from acid etching and repeated cleaning. The labor associated with the replacement is the same, regardless of the different mist eliminators they are replaced with.

Option 3 – Install Upgraded Mist Eliminator Packing
Newer design, tighter-spaced j-hook polysulfone mist eliminator packing is available from various manufacturers. The newer design with tighter spacing results in increased moisture removal from the flue gas. Additionally, the polysulfone material will not etch and will maintain superior performance when compared to the existing stainless steel mist eliminator packing.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3, upgrade mist eliminator packing, is the preferred option to reduce stack moisture and ME packing cleaning time.

Capital Project Analysis

Project Name:	ST3 Generator Auto Voltage Regulator Upgrade
Project Location:	Apache Station
Project Number:	5-01241
Estimated Cost:	$ 430,000 *Including* $ 9,000 IDC
In Service Month/Year:	5/2017
Anticipated Funding Source:	$ 421,000 RUS Loan Funds
	$ 9,000 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Replace the existing General Electric (GE) automatic voltage regulator (AVR) control system on unit ST3.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	2.F – Managerial and/or Board discretion
IRR:	31 %
Payback:	3.8 Year(s)
Payback Basis:	Payback based on the loss of 175 MW for 10 weeks and a 1 in 25 chance of failure, accelerating to 1 in 100 chance in the fourth year.

Background, Justification, and Need:
The main power generator converts the mechanical energy of the steam turbine into electricity. The generator provides electrical current for transmission to system loads. The current is maintained at a constant voltage by the important Automatic Voltage Regulating (AVR) control system installed on each unit. In order to generate the electricity, the generator field is excited with DC power. Regulation of this DC excitation maintains the output voltage. This AVR control system also controls MW, MVAr, frequency, and power factor. This control system is essentially the brain of the generator.

The current AVR control system is a GE model EX2000. The system was installed on unit ST3 in 1997. GE stopped producing the EX2000 in 2004. GE has notified the industry that the EX2000 equipment will no longer be supported after the year 2010. In order to preserve the design reliability of the unit, this system needs to be replaced.

Capital Project Analysis

Alternatives Reviewed:
Option 1 – Do Nothing
Doing nothing will result in increasing risk of a major forced outage should the current control system fail. A card or component failure means the possibility of repair, but will require creative and time-intensive repair due to the lack of OEM support.

Option 2 – Search For and Procure Spares for Existing AVR System
This option is an economical approach, but it will be hard to find new obsolete stock. If found, the possibility of a second AVR system failure will put the unit in the same predicament it is in now.

Option 3 – Replace the Existing AVR Control System
This option will require the specification and bidding of a new automatic voltage control system for unit ST3.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3, replace the existing Automatic Voltage Control system, is the prudent and lowest cost option for AEPCO's Member-customers.

Capital Project Analysis

Project Name:	ST1 Main Step-Up XFMR Bushing Replace
Project Location:	Apache Station
Project Number:	5-01243
Estimated Cost:	$ 112,000 *Including* $ 980 IDC
In Service Month/Year:	11/2017
Anticipated Funding Source:	$ 111,020 RUS Loan Funds
	$ 980 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Replace the original bushings on the ST1 main step-up transformer. The bushing replacement will require draining, processing, and refilling the oil in the transformer.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	2.F – Managerial and/or Board discretion
IRR:	IRR Not Calculated
Payback:	Payback Not Calculated
Payback Basis:	

Background, Justification, and Need:
The ST1 main step-up transformer bushings are original and approximately 48 years old. AEPCO has received excellent life from these bushings, but they are showing their age. Replacement of these bushings is recommended by AEPCO's insurer Factory Mutual (FM) Global.

Large power transformers belong to the most expensive and strategically important components of any power generation and transmission system. Although the original ST1 transformer is in good condition, its bushings are the old U-type that the industry cautions can fail without warning. Bushings are the weakest transformer component that cause up to one-third of all transformer failures. If a bushing fails, it can cause a four-week outage and/or a major failure in the transformer, which would lead to a new transformer (one-year outage) or transformer rewind (six-month outage).

Alternatives Reviewed:
Option 1 – Do Nothing
If nothing is done regarding these original bushings, the risk of bushing failure becomes quite high and increases with time.

Option 2 – Repair or Rebuild the Bushing
Unfortunately, because of the way that bushings are fabricated, rebuilding them is not possible.

Option 3 – Replace the Existing Original Bushings
Replacing the bushings is the best option for significantly reducing the risk of bushing and subsequent transformer failure.

Safety Considerations:
Explosion and fire resulting from a bushing fault.

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3 is the lowest-cost option to significantly reduce the risk of ST1 main step-up transformer failure. In some cases, bushings have exploded without any signs of fault prior to failure. In 1996, a main step-up transformer at Dairyland Power Cooperative faulted because of an apparently good U-type transformer bushing.

Capital Project Analysis

Project Name:	ST3 NOx Reduction Upgrades	
Project Location:	Apache	
Project Number:	5-01283	
Estimated Cost:	$ 9,970,000	*Including* $ 270,000 IDC
In Service Month/Year:	4/2017	
Anticipated Funding Source:	$ 9,700,000	RUS Loan Funds
	$ 270,000	General Funds
	$ 0	Other
RUS Environmental Approval:	Anticipated	
RUS General Funds Approval:	Anticipated	

Recommendation:
It is recommended to install a low NOx burners system on ST3, along with selective non-catalytic reduction systems, to comply with the ADEQ/EPA nitrous oxide emission limit of 0.23 lbs./MMBtu.

Economics / Justification:

Project Type:	New Construction
Budget Priority Code:	2.A – Legally required work
IRR:	IRR Not Calculated
Payback:	Payback Not Calculated
Payback Basis:	No payback has been calculated for this project.

Background, Justification, and Need:
ST3 current nitrous oxide (NOx) emission limit is 0.8 lbs./MMBtu. The ADEQ/EPA SIP/FIP will lower the ST3 NOx limit to 0.23 lbs./MMBtu. This project will be completed in conjunction with ST3 SNCR installation to optimize capital and O&M costs while meeting required NOx limits. Extensive planning has shown that continuing to burn coal on ST3 with the required emission controls will be the lowest cost base resource for AEPCO post-2017.

Alternatives Reviewed:
Option 1 – Do Nothing
This option will require ST3 to be idled on December 5, 2017 as the unit will not meet required NOx limits after that date.

Option 2 – Install Selective Catalytic Reduction (SCR)
This option would install ammonia injection with a catalyst, and similar modifications for burners and ductwork as in Option 3 below, to control NOX emissions. Costs for an SCR catalyst are prohibitively expensive and will reduce emission levels below what is required by ADEQ/EPA.

Option 3 – Install Low NOx Burners System
This option installs low nitrous oxide burners, additional over-fire air, tertiary air, ductwork and additional controls to the burner front, wind-box, and secondary air systems. This low NOx burners system, in conjunction with ST3 SNCR installation, will optimize the capital and O&M costs of NOx compliance. The system will require extensive modifications to ductwork with minimal modifications for boiler pressure parts.

Safety Considerations:
Modifications to the controls, burners, dampers, and ductwork must consider NFPA standards for safety.

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3, install low NOx burners system in conjunction with SNCR installation, is the most economical solution for nitrous oxide compliance and is recommended by Engineering.

Capital Project Analysis

Project Name:	ST3 SDAS Towers Outlet Upgrade
Project Location:	Apache
Project Number:	5-01315
Estimated Cost:	$ 1,144,000 *Including* $ 27,000 IDC
In Service Month/Year:	4/2017
Anticipated Funding Source:	$ 1,117,000 RUS Loan Funds
	$ 27,000 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Anticipated

Recommendation:
Replace the original ST3 tower outlet where the scrubbed flue gas from the scrubber tower enters the outlet duct. The section to be replaced lies between the outlet of the scrubbers and connects to the outlet expansion joint. It should be noted that by lining this duct, all the ducts clear to the stack will be nickel alloy (hastelloy) lined.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	18 %
Payback:	10.1 Year(s)
Payback Basis:	1 in 100 chance of ductwork failure due to structural integrity degradation (loss of 5 days' power, replacement emergency power).

Background, Justification, and Need:
The ST3 scrubber outlet project will remove and replace the existing duct with new duct that has a C-276 nickel alloy wallpaper applied to the interior of the duct. This estimate includes the cost of material and installation as well as the costs for project management, construction inspection, interest during construction, contingency, etc.

The duct is exposed to a constant flow of corrosive exhaust products and typically requires regular stripping and replacement of the protective coating used on the interior surface. Additionally, corroded steel turning vanes, support structure, and areas of the duct walls typically need replacement prior to recoating. The estimated cost of repairs has varied over the years, but it will continue to occur since patching and coating are only temporary cures. Replacement of the outlet duct with the hastelloy-lined duct is expected to be a one-time replacement that will eliminate the strip, repair, and recoat process for the life of the unit.

Capital Project Analysis

Alternatives Reviewed:
Option 1 – Do Nothing
Doing nothing and continuing to repair and recoat the ducts and turning vanes every overhaul may work for a short period of time. Eventually these ducts will need replacement as more and more steel is removed and the structure is being held up only by layers of organic coatings.

Option 2 – Line Duct with Hastelloy
Lining the duct with C-276 hastelloy is an option, but is very difficult to install. Due to the geometry inside the outlets and the location of the turning vanes, physically welding the C-276 into position will be very problematic. In addition to the tight geometry, the base metal is corroded to the point it needs to be replaced in order to ensure adequate structural strength.

Option 3 – Replace Duct with Hastelloy-Lined Duct
Replacing the existing lined carbon steel duct with a new carbon steel duct that is lined with 1/16" hastelloy will lead to a permanent repair. The C-276 hastelloy has shown resistance to the acidic environment found in the outlet flue.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends Option 3 as it is the least expensive, most permanent repair choice to restore the duct to its original design and reliability.

Capital Project Analysis

Project Name:	ST3 Turbine Blades Upgrade
Project Location:	Apache
Project Number:	5-01313
Estimated Cost:	$ 163,000 *Including* $ 2,700 IDC
In Service Month/Year:	5/2017
Anticipated Funding Source:	$ 160,300 RUS Loan Funds
	$ 2,700 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
It is recommended that both the 9th and 10th stage buckets of Unit 3 turbine be replaced during the 2017 Major Overhaul.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	403 %
Payback:	0.2 Year(s)
Payback Basis:	Based on 1 week outage at $25/MWh price difference, 80% CF.

Background, Justification, and Need:
A steam turbine rotor audit/inspection was performed during the 2011 Major Overhaul on Unit 3. The inspection found that the 9th stage buckets had evidence of heavy foreign object damage (FOD) on the inlet side of the blades. Additionally, coating was spalling at the damaged locations and going down stream. The 10th stage buckets were also found to have damage. These non-coated buckets had significant moderate and small size impacts to the inlet side of the blades. The recommendation was made to replace the two rows during the next major outage in 2017.

Alternatives Reviewed:
Option 1 – Do Nothing
This option will result in a continual decline in turbine efficiency and possible catastrophic failure over time.

Option 2 – Repair IP Bucket Rows 9 and 10
This option was used during the last overhaul in 2011 and bought another 6 years of service life. Turbine efficiency will continue to slowly decline, as will the structural integrity of the buckets until failure.

Option 3 – Replace Bucket Rows 9 and 10
This is the preferred option. This option will help restore IP turbine efficiency, increase turbine reliability, and will minimize the risk of blade failure.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3 is the preferred option. This option will help restore the ST3 IP turbine to its original efficiency and reliability.

Capital Project Analysis

Project Name:	ST3 Turbine Valve Stem Upgrade
Project Location:	Apache
Project Number:	5-01314
Estimated Cost:	$ 114,000 *Including* $ 2,000 IDC
In Service Month/Year:	5/2017
Anticipated Funding Source:	$ 112,000 RUS Loan Funds
	$ 2,000 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Recommend that both the turbine control and combined reheat valve stems be replaced with Inconel 901 material.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	17 %
Payback:	5.6 Year(s)
Payback Basis:	Reduced material and labor costs of changing out current valves.

Background, Justification, and Need:
Continuous replacement of turbine control valve stems has been necessary over the last couple of overhauls due to excessive oxide buildup and bent valve stems. It has been recommended by Jim Jones, EEC technical director, that we upgrade the valve stems to Inconel 901 material and reduce the frequency of repair and maintenance costs.

Alternatives Reviewed:
Option 1 – Do Nothing
This option will result in the increasing potential for valve stem binding and a bent CV shaft.

Option 2 – Repair
This option will result in risking the possibility of turbine valve binding issues during operation due to oxide buildup on the shaft. This would be a short-term, temporary fix.

Capital Project Analysis

Option 3 – Replace with OEM Material (422ss)
This option is what we've been doing over the last few overhauls. The risk for valve stem binding due to oxide buildup still exists, as does the potential for a bent shaft. This option is costing approximately $34,000 every 3 years.

Option 4 – Replace and Upgrade Valve Stem Material with Inconel 901.
This is the preferred option. This option significantly reduces the risk of turbine valve binding issues as well as the potential for a bent shaft. Inconel material is much stronger than 422ss and does not accumulate oxide buildup, which significantly reduces the possibility of binding problems.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 4 is the preferred option. This option significantly reduces the risk of turbine valve binding issues as well as the potential for a bent shaft. Inconel material is much stronger than 422ss and does not accumulate oxide buildup. The replacement of the turbine valve stem will restore the valve's original design and reliability.

Capital Project Analysis

Project Name:	ST3 ID Fans Speed Changer Circuit Upgrade
Project Location:	Apache
Project Number:	5-01316
Estimated Cost:	$ 39,000 *Including* $ 600 IDC
In Service Month/Year:	5/2017
Anticipated Funding Source:	$ 38,400 RUS Loan Funds
	$ 600 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Upgrade the speed circuit that controls the speed of the ST3 ID Fan.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	135 %
Payback:	0.7 Year(s)
Payback Basis:	Saving of 1 boiler trip per year. Replacement power @ $50/MWh for 6 hours.

Background, Justification, and Need:
ST3 has two induced draft (ID) fans that pull (induce) the combustion gases from the boiler and push them out the stack. The ID fans are set up to run on two different speeds: fast and slow. The different speeds allow the unit to run at different loads more efficiently.

The circuits that control the speed changes consist of multiple mechanical relays. These different relays have, in the past, proved to be only semi-reliable. Occasionally when making the speed change the ID fan will trip. These trips, while infrequent, cause the operators to shy away from making the changes necessary for the load of the unit. The operators will opt to keep the fans running on high and throttle them back with the use of dampers, causing extra wear on the dampers and higher amps on the motors.

When ST3 switches to natural gas fuel, the forecast is for this unit to perform many load changes and run at lower loads more often. When running at lower loads and when varying the load, the speed of the ID fans becomes more critical than when just running close to full load. By upgrading the speed control circuits on the fans, the reliability of switch will be restored. One the fan can switch between high and low speeds reliably, the operators will regulate the speeds of the fan for the load of the unit.

Alternatives Reviewed:
Option 1 – Do Nothing
Doing nothing will leave the speed control circuits in the same condition they are. The ID fans will be kept in a "high" mode and will use excess amps at periods of low loads.

Option 2 – Upgrade the ID Fan Inlet Dampers
By upgrading the ID fan inlet dampers, the wear issues from throttling the ID fan will be minimized. However, the fan will still be drawing more amps than are required.

Option 3 – Upgrade the ID Fan Speed Control Circuit
By upgrading the speed control circuit, the ID fans will be able to switch from high to low speed without increased risk of tripping the fan.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends Option 3 as the most economical method to restore the original reliability of the ID Fans.

Capital Project Analysis

Project Name:	ST3 SNCR Installation	
Project Location:	Apache	
Project Number:	5-01317	
Estimated Cost:	$ 3,661,000	*Including* $ 75,000 IDC
In Service Month/Year:	4/2017	
Anticipated Funding Source:	$ 3,586,000	RUS Loan Funds
	$ 75,000	General Funds
	$ 0	Other
RUS Environmental Approval:	Anticipated	
RUS General Funds Approval:	Anticipated	

Recommendation:
It is recommended to install selective non-catalytic reduction systems on ST3 in conjunction with ST3 low NOx burners to comply with the ADEQ/EPA nitrous oxide emission limit of 0.23 lbs./MMBtu.

Economics / Justification:

Project Type:	New Construction
Budget Priority Code:	2.A – Legally required work
IRR:	IRR Not Calculated
Payback:	Payback Not Calculated
Payback Basis:	No payback has been calculated. Emissions-reduction required project.

Background, Justification, and Need:
ST3 current nitrous oxide (NOx) emission limit is 0.8 lbs./MMBtu. The ADEQ/EPA SIP/FIP will lower the ST3 NOx limit to 0.23 lbs./MMBtu. This project will be completed in conjunction with ST3 low NOx burners system to optimize capital and O&M costs while meeting required NOx limits. Extensive planning has shown that continuing to burn coal on ST3 with the required emission controls will be the lowest cost base resource for AEPCO post-2017.

Alternatives Reviewed:
Option 1 – Do Nothing
This option will require ST3 to be idled on December 5, 2017 as the unit will not meet required NOx limits after that date.

Option 2 – Install Selective Catalytic Reduction (SCR)
This option is the same as Option 3 except it includes a catalyst to convert all NOx to N2. Costs for an SCR catalyst are prohibitively expensive and will reduce emission levels below what is required by ADEQ/EPA.

Option 3 – Install Selective Non-Catalytic Reduction (SNCR)
This option installs an ammonia injection system to the convection pass of the boiler. This SNCR system will be in conjunction with ST3 Low NOx burners to optimize the capital and O&M costs of NOx compliance. The injection system may have urea with a converter as the base chemical, in lieu of ammonia, to minimize safety issues with storing aqueous ammonia near the boilers.

Safety Considerations:
Urea/ammonia storage and handling issues.

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3, install selective non-catalytic reduction system, in conjunction with ST3 low NOx burners system, is the most economical solution for nitrous oxide compliance and is recommended by Engineering.

Capital Project Analysis

Project Name:	ST3 Boiler Splash Screen Upgrade
Project Location:	Apache
Project Number:	5-01312
Estimated Cost:	$ 155,000 *Including* $ 2,000 IDC
In Service Month/Year:	4/2017
Anticipated Funding Source:	$ 153,000 RUS Loan Funds
	$ 2,000 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
Replace the current style of splash screens with Flexible Hinge Style (FHS) baffles. The current splash screens are replaced every one to two outage cycles. By upgrading to the newly designed screen they should last multiple outage cycles resulting in cost savings and better raft header protection.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	4.A – Economic Justification – payback greater than two years
IRR:	9 %
Payback:	8.1 Year(s)
Payback Basis:	Savings based on decreased maintenance on the original splash screen design.

Background, Justification, and Need:
The current splash screens do not hold up well and also allow some water to splash onto the raft header, creating thermal shock. These screens protect the lower pressure parts of the boiler from water splashing up on hot parts as combustion slag falling out of the furnace. The splash screens need to be replaced every one to two outages due to deterioration.

By replacing the screens with baffles, the raft header splash protection will be improved. The thermal shock on the raft header, due to water splashing up on hot pressure parts, is causing thermal stress cracking of the lower tube-to-header connections. These cracks have been weld-repaired in past outages. By installing a baffle that will hold up in the harsh environment, the cracking on the lower raft headers will be minimized.

Capital Project Analysis

Alternatives Reviewed:
Option 1 – Do Nothing
Continue replacing the existing splash screens every one to two outages and experience continual degradation and repair costs of the lower raft headers.

Option 2 – Replace Splash Screens with New Designed Screen
Upgrade the existing screens with FHS design screen.

Safety Considerations:
None

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Staff recommends Option 2. By upgrading our current screens, we can expect to reduce maintenance dollars and also provide better protection to the lower raft header.

Capital Project Analysis

Project Name:	ST3 SDAS Bypass Duct Upgrade	
Project Location:	Apache	
Project Number:	5-01324	
Estimated Cost:	$ 1,100,000	*Including* $ 12,500 IDC
In Service Month/Year:	6/2015	
Anticipated Funding Source:	$ 1,087,500	RUS Loan Funds
	$ 12,500	General Funds
	$ 0	Other
RUS Environmental Approval:	Anticipated	
RUS General Funds Approval:	Anticipated	

Recommendation:
Dry out the bypass duct to protect it from corrosive acid precipitates in the flue gas stream.

Economics / Justification:

Project Type:	System Improvement
Budget Priority Code:	2.F – Managerial and/or Board discretion
IRR:	4 %
Payback:	11 Year(s)
Payback Basis:	Save $300,000 per outage in replacing ductwork and re-coating.

Background, Justification, and Need:
Unit ST3 was designed with wet flue gas desulfurization (WFGD) technology to remove acid gases from the flue gas prior to entering the stack. The WFGD is effective at removing some acid gases from the stack, but in the process moisture is added to the flue gas stream. This leads to a very moist flue gas. In the past, the bypass dampers have leaked just enough flue gas around the WFGD towers to add heat back to the treated flue gas stream and effectively dry it out above its condensation point.

During the last overhaul, the bypass dampers were replaced with a zero-leakage damper to allow for compliance of tighter emissions requirements. This elimination of the bypass gases has allowed the flue gas to remain at saturation and moisture is now forming in the ducts. The bypass duct was never designed for any acid precipitation and the acid is corroding the carbon steel duct.

The carbon steel duct needs some protection against the corrosive liquid forming inside the duct.

Capital Project Analysis

Alternatives Reviewed:

Option 1 – Do Nothing

Doing nothing will result in acids precipitating out in the bypass duct, eventually corroding the floor of the duct to the point of flue gas leak.

Option 2 – Bypass a Portion of the Flue Gas

Bypassing a portion of the flue gas will dry out the bypass duct. Unfortunately, when stricter emission limits take effect on ST3 (April 2016) ST3 will not be able to comply with either Hg emissions or SO2 emissions.

Option 3 – Hastelloy Wallpaper the Interior of the Bypass Duct

By installing hastelloy on the interior of the bypass duct, the carbon steel shell will be protected from the corrosion of the acid precipitates.

Option 4 – Install a Bypass Damper at the Converging Tee

By installing a zero-leakage bypass damper at the converging tee, the bypass duct will be kept dry. Once the duct is dry and no longer exposed to flue gases, the corrosion will halt.

Safety Considerations:

None

Environmental Considerations:

N/A – Categorical Exclusion

Conclusion:

Staff recommends Option 4 as the most economical solution to protect the bypass duct.

Capital Project Analysis

Project Name:	ST3A Replace Mill Throat Liners
Project Location:	Apache Station
Project Number:	5-00852
Estimated Cost:	$ 192,000 *Including* $ 1,000 IDC
In Service Month/Year:	4/2017
Anticipated Funding Source:	$ 191,000 RUS Loan Funds
	$ 1,000 General Funds
	$ 0 Other
RUS Environmental Approval:	Anticipated
RUS General Funds Approval:	Not Required

Recommendation:
The coal pulverizer (mill) throat liners are reaching the end of their useful lives. This project will replace the mill end throat liners on both ends of the mill with liners of a similar material and design. The replacement is scheduled in conjunction with the scheduled generating unit overhaul.

Economics / Justification:

Project Type:	Ordinary Replacement
Budget Priority Code:	2.F – Managerial and/or Board discretion
IRR:	84 %
Payback:	1.2 Year(s)
Payback Basis:	Payback based on running without ball mill throat liners and replacing rotating mill every three years from wear.

Background, Justification, and Need:
The mill throat liners are designed to protect the barrel of the mill from wear. They also have flights cast into them that convey the coal into the pulverizer. The flights have worn to the point that the volume of coal they can convey will soon be less than required, which can result in mill end pluggages. These pluggages are labor intensive to clean and increase the possibility of mill puffs.

The liners are the original equipment, installed in the late 1970s, and measurements of the flights indicate they are reaching the end of their useful lives. Replacing the liners will restore the dimension of the flights to original design dimensions and performance.

Alternatives Reviewed:
Option 1 – Do Nothing
If the throat liners are not replaced, the dimensions of the flights will wear to the point they fail structurally and will no longer convey the coal into the pulverizer, resulting in pluggages of the

mill ends. This would result in derating the generation unit by 60 MW. Replacement power costs could be 60 MW X $55.00/MWh X 8760 hrs./yr. = $28,908,000 annually.

Option 2 – Run the liners to the point they no longer perform their function and the mill must be shut down for replacement on an emergency basis. Normal delivery time for new throat liners is 26 weeks. This would result in derating the generating unit by 60 MW for 28 weeks to procure new liners and install them. Replacement power costs could be 60 MW X $55.00/MWh X 4,704 hrs. = $15,523,200 plus the additional costs of craft labor working around the clock to make the repairs.

Option 3 – Replace the throat liners in conjunction with a scheduled generation unit overhaul Planned replacement of the liners as a proactive measure will allow the work to be done during a scheduled overhaul. . This will allow the scheduling of manpower and replacement parts to be the most cost effective and reduce the risk of future forced derates or outages due to throat liner failure in service.

Safety Considerations:
Mill end pluggages can result in explosions, which can injure personnel and damage equipment.

Environmental Considerations:
N/A – Categorical Exclusion

Conclusion:
Option 3 is the lowest cost and the preferred option. . Replacing the throat liners before they are worn to the point mill performance is affected will help to maintain generating unit reliability and safety.

G|K
Gallagher&Kennedy

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September 24, 2015

Thomas M. Broderick, Director
Utilities Division
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Re: *Arizona Electric Power Cooperative's ("AEPCO) Notice of Proposed Modifications to Its 2012-2014 Construction Work Plan, Decision No. 73728, Docket No. E-01773A-12-0192*

Dear Mr. Broderick:

In Decision No. 73728, dated February 20, 2013 (the "Decision"), the Commission approved AEPCO's request for the RUS/FFB loan financing of its 2012-2014 Construction Work Plan ("CWP") in an amount not to exceed $34,042,700. In the Decision, the Commission also approved continuation of the procedure authorizing amendments to the CWP without the need to file an amended application as follows:

> Arizona Electric Power Cooperative, Inc. may change the specific facilities to be financed in the CWP without the necessity of filing an amended financing application conditioned upon the following: 1) the total amount financed remains below the financing amount authorized; 2) that Arizona Electric Power Cooperative, Inc. file in this docket a description of any proposed modifications to the Construction Work Plan which cost more than $500,000, and that such modifications substantially conform to the purposes of the 2012-2014 Construction Work Plan; 3) that Staff has not filed an objection to the proposed modifications within 60 days of the date Arizona Electric Power Cooperative, Inc. files the proposed changes; and 4) that the proposed modifications be deemed approved for financing purposes only.[1]

AEPCO has deleted as unnecessary several projects authorized by the Decision and constructed other projects at less cost than originally estimated. As a result, there remains unused approximately $15.2 million in available funds under the S-8 RUS Loan and the amount authorized by the Commission. Because the RUS has encumbered these remaining funds in the

[1] Third Full Ordering Paragraph at page 7 of the Decision.

U.S. Treasury, AEPCO has been asked to identify other projects that could be funded with these monies so that RUS will not have to go through another Congressional budget process to re-encumber the committed funds.

Attached as Exhibit A is a schedule showing the disposition of projects originally approved in the Decision.[2] Attached as Exhibit B is a schedule identifying the projects that AEPCO proposes to fund using the available, remaining loan funds. As required by the Decision, (1) the total amount financed will remain below the Commission-authorized level of $34,042,700 and (2) the modifications substantially conform to the purpose of the CWP, which is to make necessary improvements, upgrades and replacements to AEPCO's generation plant to meet reliability and service quality standards.

By the terms of the Decision, Staff does not need to take affirmative action on this request for the proposed changes to take effect. The changes will take effect after sixty (60) days if no objection is filed.

Staff's assistance in relation to this matter is appreciated. If we can supply additional information concerning these CWP modifications, please contact me or Gary Pierson at AEPCO (602-269-3415, ext. 5364).

Sincerely,

GALLAGHER & KENNEDY, P.A.

By:
Jennifer A. Cranston

JAC:njk
Attachments
cc w/attachments: Thomas M. Broderick (delivered)
10421-0068/5057612

Original and 13 copies filed with Docket
Control this 24th day of September, 2015.

[2] Exhibit A references projects from AEPCO's 2012-2014 CWP as well as its 2009-2011 plan because the projects approved by the Decision included certain unfunded projects remaining from AEPCO's 2009-2011 plan.

G.K

EXHIBIT A

Exhibit A
Arizona Electric Power Cooperative, Inc.
Projects Approved Under Decision No. 73728

Line	RUS Project #	Project Name	Project Number	Approved under Decision No. 73728	Final S-8 Budget	Final Project Cost	Budget Change	Explanation
1		**2012 - 2014 Construction Work Plan, Am. #0**						
2	1200.1	ST2 Turbine Control System Upgrade	5-00641	$ 937,000	$ 937,000	$ 949,681.06	$ -	
3	1200.2	ST2C Coal Piping Elbows Upgrade	5-01212	$ 220,500	$ 220,500	225,856.98	$ -	
4	1200.3	ST3C Coal Piping Elbows Upgrade	5-01213	$ 227,500	$ 227,500	231,493.89	$ -	
5	1200.4	ST2C Mill Trunnion Bearings	5-00857	$ 121,000	$ 121,000	129,346.22	$ -	
6	1200.5	ST3B Mill Trunnion Bearings	5-00859	$ 125,000	$ 125,000	117,331.49	$ -	
7	1200.6	ST2 Classifier Replacement	5-00920	$ 1,105,000	$ 1,105,000	909,252.37	$ -	
8	1200.7	ST3 Classifier Replacement	5-00921	$ 1,181,000	$ -	-	$ (1,181,000)	Deleted
9	1200.8	ST2 Igniter Scanner Upgrade	5-01002	$ 99,500	$ 99,500	91,070.64	$ -	
10	1200.9	ST2 Main Flame Scanner Modification	5-01221	$ 57,300	$ 57,300	48,117.88	$ -	
11	1200.13	ST2 Precipitator Platform Addition	5-01226	$ 47,500	$ -	-	$ (47,500)	Deleted
12	1200.14	ST3 Precipitator Platform Addition	5-01228	$ 48,000	$ -	-	$ (48,000)	Deleted
13	1200.15	ST2 Generator Relay Upgrade	5-01168	$ 68,000	$ 136,000	119,896.72	$ 68,000	Revised Budget
14	1200.16	Apache Land Procurement 2012	5-01260	$ 1,200,000	$ -	-	$ (1,200,000)	Deleted
15	1200.17	ST2/3 Turbine Pilot Valve Critical Spare	5-01216	$ 197,000	$ -	-	$ (197,000)	Deleted
16	1200.18	Misc HVAC Replacement 2012	5-01231	$ 106,000	$ -	-	$ (106,000)	Deleted
17	1200.19	Misc HVAC Replacement 2013	5-01244	$ 109,000	$ -	-	$ (109,000)	Deleted
18	1200.20	Misc HVAC Replacement 2014	5-01245	$ 112,500	$ -	-	$ (112,500)	Deleted
19	1200.21	ST2 Precipitator Electrodes Replacement	5-01217	$ 456,000	$ 456,000	414,431.87	$ -	
20	1200.22	ST2 Precipitator Rappers Upgrade	5-01218	$ 317,000	$ 317,000	242,931.23	$ -	
21	1200.23	ST2/3 Boiler Oxygen Reduction	5-01262	$ 190,000	$ -	-	$ (190,000)	Deleted
22	1200.24	ST2 SDAS Tower Outlet Duct/Damper Upgrade	5-00985	$ 1,685,000	$ 2,022,800	2,000,147.05	$ 337,800	Revised Budget
23	1200.25	ST2 Stack Liner Corrosion Protection	5-01188	$ 4,580,000	$ 4,580,000	4,349,280.27	$ -	
24	1200.26	ST2 Breeching Duct Upgrade	5-01202	$ 983,000	$ -	-	$ (983,000)	Deleted
25	1200.27	ST2/3 Chimney Roof Upgrade	5-01230	$ 195,000	$ 195,000	206,668.90	$ -	
26	1200.28	Centac Compressor Re-build	5-01183	$ 307,000	$ 452,000	466,397.77	$ 145,000	Revised Budget
27	1200.29	Miscellaneous Piping Replacement, 2012	5-01225	$ 250,000	$ 250,000	233,637.42	$ -	
28	1200.30	ST2 Upper Tube Bend Replacement	5-01211	$ 429,000	$ 429,000	333,575.64	$ -	
29	1200.31	ST2 Generator AVR Upgrade (EX2000)	5-01215	$ 363,000	$ -	-	$ (363,000)	Deleted
30	1200.32	Conveyor 2 Belt Replacement	5-01224	$ 213,500	$ 213,500	148,902.34	$ -	
31	1200.33	Conveyor 3 Replacement	5-01238	$ 120,500	$ 120,500	77,001.66	$ -	
32	1200.34	High Tower Riser Upgrade	5-00784	$ 75,000	$ 150,000	140,521.48	$ 75,000	Revised Budget
33	1200.35	ST2/3 Crane Rail Upgrade	5-01161	$ 49,300	$ -	-	$ (49,300)	Deleted
34	1200.36	ST3 Turbine Lube Oil Cooler Upgrade	5-01203	$ 82,000	$ 82,000	88,342.53	$ -	
35	1200.37	ST3 West Water Wall Tubing Replacement	5-01214	$ 514,000	$ 514,000	298,022.10	$ -	
36	1200.38	ST3 SDAS Mist Eliminator Upgrade	5-01229	$ 308,000	$ -	-	$ (308,000)	Deleted
37	1200.39	ST3 Precipitator Electrodes Replacement	5-01234	$ 401,000	$ 401,000	329,553.71	$ -	
38	1200.40	ST3 Precipitator Rappers Upgrade	5-01235	$ 326,000	$ 326,000	176,043.91	$ -	
39	1200.41	Miscellaneous Piping Replacement, 2013	5-01236	$ 200,000	$ 200,000	223,939.95	$ -	
40	1200.42	ST3 Main Step-Up Xfmr Bushing Replace	5-01240	$ 143,500	$ 143,500	124,988.62	$ -	
41	1200.43	ST3 Generator AVR Upgrade (EX2000)	5-01241	$ 371,000	$ -	-	$ (371,000)	Deleted
42	1200.44	Tripper Dust Suppression System	5-01248	$ 278,000	$ 371,000	443,075.77	$ 93,000	Revised Budget
43	1200.45	Deep Well Line Extension to Curry #8	5-01255	$ 326,000	$ -	-	$ (326,000)	Deleted
44	1200.46	ST3 Upper Breeching Duct Upgrade	5-01256	$ 1,425,600	$ 1,425,600	889,121.40	$ -	
45	1200.47	ST2 Condenser Air Removal Re-tube	5-01169	$ 595,000	$ -	-	$ (595,000)	Deleted
46	1200.48	ST2 East Water Wall Tubing Replacement	5-01209	$ 526,000	$ -	-	$ (526,000)	Deleted
47	1200.49	ST2 SDAS Mist Eliminator Upgrade	5-01222	$ 325,000	$ -	-	$ (325,000)	Deleted
48	1200.50	ST2 Turbine Packing Replacement	5-01253	$ 137,500	$ 137,500	131,406.41	$ -	
49	1200.51	ST2 Air Preheater Basket Replacement	5-01254	$ 1,110,000	$ -	-	$ (1,110,000)	Deleted
50	1200.52	ST2 Upper Breeching Duct Upgrade	5-01257	$ 1,469,000	$ -	-	$ (1,469,000)	Deleted
51	1200.53	ST2 Turbine Lube Oil Cooler Upgrade	5-01258	$ 84,100	$ -	-	$ (84,100)	Deleted
52	1200.54	GT4 Catalyst Replacement	5-00924	$ 886,000	$ -	-	$ (886,000)	Deleted

53	1200.55	GT4 Stage 1 HPC Replacement	5-01210	$ 120,000	$ -	-	$ (120,000)	Deleted
54	1200.56	ST1 Low Nox Burners	5-01242	$ 2,052,000	$ -	-	$ (2,052,000)	Deleted
55	1200.57	ST1 Main Step-Up Xfmr Bushing Replace	5-01243	$ 96,500	$ -	-	$ (96,500)	Deleted
56		Total for CWP 2012-2014		$ 27,951,300	$ 15,815,200	$ 14,140,037	$ (12,136,100)	
57								
58								
59		**2009 - 2011 Construction Work Plan, Am. #3**						
60	1200.72	ST2/3 Turb/Gen Brgs Crit Spare	5-00801	$ 248,300	$ 248,300	$ 180,009.08	$ -	
61	1200.75	ST1 No. 1 Circ Water Pump Rebuild	5-00929	$ 150,000	$ 150,000	125,855.70	$ -	
62	1200.82	ST1 Turbine Blades Replacement	CAPG1.01107	$ 300,000	$ 300,000	265,624.76	$ -	
63	1200.83	ST1 O2 Probes Replacement	5-01118	$ 61,000	$ -	-	$ (61,000)	Deleted
64	1200.85	ST3 O2 Probes Replacement	5-01120	$ 90,000	$ 90,000	97,211.33	$ -	
65	1200.90	ST2/3 Conveyor 1 Fire Protection Upgrade	5-01158	$ 235,000	$ -	-	$ (235,000)	Deleted
66	1200.92	ST2/3 Duct Opacity Monitor Installation	5-01164	$ 146,000	$ 146,000	117,022.15	$ -	
67	1200.99	ST3 SDAS Lower Quench Nozzle Upgrade	5-01178	$ 131,000	$ 131,000	39,279.41	$ -	
68	1200.100	ST3 Large Fan Lube Oil Skids Upgrades	5-01140	$ 59,000	$ 59,000	51,415.61	$ -	
69	1200.1	3A/3B Coal Piping Elbow Upgrades	5-01179	$ 504,000	$ 504,000	400,921.67	$ -	
70	1200.1	ST1 Cold Reheat Attemperator Spray Liner	5-01152	$ 167,000	$ 167,000	130,663.63	$ -	
71	1200.1	ST3 Generator Relay Upgrade	5-01167	$ 93,800	$ 93,800	46,412.45	$ -	
72	1200.11	ST1 Boiler Tube Replacement	5-01165	$ 425,000	$ 425,000	337,997.13	$ -	
73	1200.11	ST3 Generator SCT Replacement	5-01163	$ 147,500	$ 147,500	145,493.62	$ -	
74	1200.11	ST2/3 Chimney Roof Protection	5-01181	$ 84,000	$ 84,000	94,613.96	$ -	
75	1200.12	ST3 Main Flame Scanner Modification	5-01116	$ 50,000	$ 50,000	40,272.39	$ -	
76	1200.12	ST3 Economiser Expansion Joint Upgrade	5-01172	$ 156,000	$ 156,000	119,800.68	$ -	
77	1200.13	Backup Control Center	5-01184	$ 100,000	$ 100,000	100,000.00	$ -	
78	1200.13	ST2 Stack Liner Coating Replacement 2010	5-01186	$ 600,000	$ 600,000	599,969.09	$ -	
79	1200.13	ST2/3 Spare BFP Motor	5-01190	$ 200,000	$ 200,000	180,956.45	$ -	
80	1200.130	ST3 Stock Feeder Ctrl Brd Upgrades	5-01191	$ 57,000	$ 57,000	37,535.30	$ -	
81	1200.13	ST2/3 Sluice Pump C Rebuild	5-01193	$ 80,000	$ 80,000	29,304.90	$ -	
82	1200.13	Apache Heavy Equipment Shop Roof Upgrade	5-01195	$ 41,700	$ 41,700	28,252.00	$ -	
83	1200.13	Apache Warehouse 800 Roof Upgrade	5-01196	$ 52,600	$ 52,600	34,397.00	$ -	
84	1200.14	Acquisition of Dressler Property	5-01199	$ 300,000	$ 300,000	223,954.50	$ -	
85	1200.14	ST2/3 CWDF Monitorung Wells	5-01200	$ 250,000	$ 250,000	31,672.26	$ -	
86	1200.14	ST3 Breeching Duct Corrosion Protection	5-01201	$ 812,000	$ 812,000	710,807.34	$ -	
87	1200.14	ST3 Turbine Packing Replacement	5-01205	$ 119,500	$ 119,500	113,012.16	$ -	
88	1200.14	4B Conveyor Belt Replacement	5-01206	$ 50,000	$ 50,000	43,064.71	$ -	
89	1200.140	ST2/3 Pulverizor Gearbox Modifications, 2011	5-01207	$ 85,000	$ 85,000	64,023.94	$ -	
90	1200.14	ST3C Mill Trunnion Bearings Replacement	5-00860	$ 125,000	$ 125,000	85,644.46	$ -	
91	1200.14	ST2/3 Crane Beam Sealing	5-01208	$ 171,000	$ 280,000	270,561.42	$ 109,000	Revised Budget
92		Total for CWP 2009-2011		$ 6,091,400	$ 5,904,400	$ 4,745,749	$ (187,000)	
93								
94		**Total for S8 Loan**		**$ 34,042,700**	**$ 21,719,600**	**$ 18,885,786**	**$ (12,323,100)**	

EXHIBIT B

Exhibit B
Arizona Electric Power Cooperative, Inc.
Additional Projects

Line	RUS No.	Project Name	Project No.	Budget
	2012 - 2014 Construction Work Plan, Am. #1			
1	1200.58	GT4 Controls Upgrade	5-01010	$ 478,000.00
2	1200.60	SDAS Annunciator Upgrade	5-01016	$ 56,000.00
3	1200.61	Fire Protection System Upgrades	5-01018	$ 104,000.00
4	1200.62	Raw Water Tanks Coatings	5-01019	$ 220,000.00
5	1200.64	Water Truck Replacement	5-01025	$ 123,000.00
6	1200.65	PA Fan Motor Critical Spare Replacement	5-01027	$ 90,000.00
7	1200.66	Pulverizer Gearbox Modification 2013	5-01032	$ 70,000.00
8	1200.67	Machine Shop Small Tool Lathe	5-01033	$ 36,000.00
9	1200.68	Telescopic Fork Lift Purchase	5-01034	$ 90,000.00
10	1200.69	ST2/3 Conveyor 1 Fire Protection Upgrade	5-01158	$ 235,000.00
11	1200.70	EHC Filtration Carts Purchase	5-01227-010	$ 41,000.00
12	1200.72	ST2/3 Cond Make-up Spray Piping Mod	5-01227-030	$ 45,000.00
13	1200.73	Chemistry Analyzer Upgrades	5-01227-040	$ 88,000.00
14	1200.74	Critical Spare 1000 KVA Transformer	5-01227-050	$ 71,000.00
15	1200.75	ST2 Converging Tee Upgrade	5-01263	$ 1,075,000.00
16	1200.76	ST2 Bypass Duct Upgrade	5-01267	$ 120,000.00
17	1200.77	ST2 Turbine Valve Retaining Ring	5-01268	$ 287,000.00
18		Total AM1		$ 3,229,000.00
19				
20	**2012 - 2014 Construction Work Plan, Am. #2**			
21	1200.79	ST3 SDAS Bypass Dampers Replacement	5-01024	$ 540,000.00
22	1200.80	ST3 Converging Tee Upgrade	5-01028	$ 1,075,000.00
23	1200.81	ST1/2/3 Lube Oil Fire Containment	5-01035	$ 475,000.00
24	1200.82	ST3 Battery Charger/Inverter Upgrade	5-01276	$ 75,000.00
25	1200.83	4B Conveyor Belt Replacement	5-01278	$ 50,000.00
26	1200.85	ST2/3 Ash PLC Replacement	5-01280	$ 300,000.00
27	1200.87	Deep Well #68 Upgrades	5-01286	$ 111,000.00
28	1200.89	ST3 Turbine LVDT Replacement	5-01290	$ 45,000.00
29	1200.90	Apache Fuel Dispensor Upgrade	5-01292	$ 55,000.00
30		Total AM2		$ 2,726,000.00
31				
32	**2012 - 2014 Construction Work Plan, Am. #3**			
33	1200.91	BFP Head Plate Critical Spare	5-01251-010	$ 62,500.00
34	1200.92	Rail Car Access Crossover	5-01251-020	$ 69,000.00
35	1200.93	ST2 Breech Duct Drains Relocate	5-01252-020	$ 35,086.00
36	1200.94	ST3 Breech Duct Drains Relocate	5-01252-030	$ 48,000.00
37	1200.95	ST2/3 Circ Wateer Pump Motor Rebuild	5-01252-050	$ 75,000.00

		ST3 Cold End APH Basket		
38	1200.96	Replacement	5-01274	$ 218,000.00
39	1200.97	ST2A Boiler Feed Pump Rebuild	5-01293	$ 80,000.00
40	1200.98	Centac Compressor 'B' Rebuild 2014	5-01303	$ 400,000.00
41	1200.99	Apache Station Boom Lift	5-01325	$ 140,000.00
42	1200.100	ST2 Battery Charger/Invertor Upgrade	5-01277	$ 95,000.00
43		Total AM3		$ 1,222,586.00
44				
45				
46	**2015-2017 Construction Work Plan**			
47	1200.1	ST2 Particulate Monitor Installation	5-01326	$ 200,000.00
48	1200.2	ST3 Particulate Monitor Installation	5-01327	$ 200,000.00
49	1200.3	ST2 Condenser Air Removal Re-tube	5-01169	$ 477,000.00
50	1200.4	ST2 Generator Auto Voltage Regulator	5-01215	$ 385,000.00
51	1200.5	ST2 Yokogawa Replacement	5-01219	$ 69,000.00
52	1200.6	ST3 Mercury Control	5-01239	$ 2,500,000.00
53	1200.7	ST2 Air Preheater Basket Replacement	5-01254	$ 1,596,000.00
54	1200.8	ST2 Feedwater Heater Level Controls	5-00939	$ 78,000.00
55	1200.9	Miscellaneous Piping Replacement 201	5-01310	$ 200,000.00
56	1200.1	ST2/3 CWDF Monitoring Well Relocai	5-01284	$ 100,000.00
57	1200.11	ST3 Air Preheater Basket Replacement	5-01294	$ 1,800,000.00
58	1200.13	ST2 ID Fan Speed Circuit Upgrade	5-01304	$ 36,000.00
59	1200.15	Apache Cathodic Protection Upgrade	5-01309	$ 136,000.00
60	1200.16	ST2 Generator Bushing Replacement	5-01320	$ 122,000.00
61		Total		$ 7,899,000.00
62				
63		**Total for S-8 Loan Financing**		**$ 15,076,586.00**

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.4 If interim funding is to be utilized for the projects in the CWP, identify the source of all elements of this expected interim funding and when the interim funding is expected to be retired and replaced with permanent funding from this new financing arrangement.

Response: Pursuant to the Commission's authorization in Decision No. 74447 in Docket No. E-01773A-14-0019, AEPCO has two unsecured, committed revolving lines of credit sufficient to provide interim funding. AEPCO will draw down the funds from the permanent financing that is the subject of its current application to repay the lines of credit as each project is placed in service.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.5 Provide the balances, if any, of "Advances in Aid of Construction" and "Contributions in Aid of Construction," as of the end of the Company's most recent fiscal year.

Response: AEPCO received a grant in 2014 through RUS's Rural Energy for America Program for a solar covered parking facility in the amount of $39,619. Additional funding for this project is being provided by one of AEPCO's Class A member distribution cooperatives (Sulphur Springs Valley Electric Cooperative) as a performance-based incentive. Total funding provided for this project is $49,810.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.6 Provide proof of notice of this matter duly published within newspapers of general circulation within the Company's service territory, as specified in the finance application form at http://www.azcc.gov/divisions/utilities/forms.asp. Identify any other method (e.g., direct mail) used to provide customer notice of the financing application, provide a copy of the notice and specify the date the notice was provided to customers and provide an affidavit attesting to the provision of the supplemental or alternate notice method.

Response: Within ten days of the filing of its application, AEPCO will publish notice of the application in the *Arizona Daily Star* and *The Kingman Daily Miner*, which are newspapers of general circulation in AEPCO's service area. AEPCO will file the appropriate affidavits of publication within thirty days of filing its application.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.7 Provide the number of customers currently served by rate class, and a brief description of each class of customers (residential, commercial, etc.).

Response: See the attached schedule summarizing AEPCO's Class A Members' Form 7 data for 2014.

1.7

Arizona Electric Power Cooperative, Inc.

Class A Member Customer Data

Form 7 Data

Average Number of Customers Served

	12/31/2014
Retail	131,410
Irrigation	1,443
Small Commercial & Industrial	16,674
Large Commercial & Industrial	48
Public Lighting	103
Other & Sales for Resale	42
	149,720

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.8 Provide a schedule detailing all financing approvals obtained by the Arizona Corporation Commission ("Commission") that remain in effect and indicate docket numbers, amounts approved, amounts drawn and any balances not yet drawn. For any balances not yet drawn, provide an explanation of why the funds have not been drawn and how the Company intends to utilize this currently available borrowing capacity.

Response: AEPCO has two financing approvals in effect.

Decision No. 73728 in Docket No, E-01773A-12-0192 approved permanent financing not to exceed $32,042,700 and interim financing not to exceed $38,907,400. As of October 31, 2015, AEPCO had drawn $13,000,000 under the permanent financing facility. AEPCO expects to utilize the full amount approved to finance the projects identified in its 2012-2014 CWP, as modified by the September 24, 2015 Notice of Proposed Modifications, attached to AEPCO's response to data request 1.3.

Decision No. 74447 in Docket No. E-01773A-14-0019 approved two unsecured, committed revolving lines of credit not to exceed the combined amount of $100,000,000. As of October 31, 2015, $5,000,000 had been drawn. AEPCO expects to pay-off and re-draw funds as needed for interim financing.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.9 If not clearly identified with the financial statements and footnotes of the financial statements provided in response to 1.1, provide a complete list of all long-term debt obligations (including capital leases). For each obligation provide: the lender's name and contact information, the initial loan amount, the current outstanding (unpaid) balance, the inception date, the maturity date(s), the annual interest rate (for variable interest rates state the basis upon which the rate is dependent and the time interval or frequency the changes are implemented), the numerical covenants such as DSC, TIER, CCR, equity-to-total capital ratio, etc. For amortizing loans, provide an amortization schedule showing the scheduled payments for principal and interest. Also, provide any other information pertinent for gaining an essential understanding of the Company's debt obligations.

Response: See the attached schedules detailing the requested information regarding loan amounts, outstanding balances, inception and maturity dates, and interest rates. Lender contact information and numerical covenants are provided in AEPCO's response to data request 1.2.

1.9

Arizona Electric Power Cooperative, Inc.

Summary of Debt Balances

As of October 1, 2015

NATURE OF OBLIGATION	TOTAL AMOUNT OUTSTANDING	PERCENT TO TOTAL	FACE RATE	ANNUALIZED INTEREST EXPENSE
FFB DEBT	$156,471,916.51	86.412%	3.892%	$6,089,664.05
CFC SERIES 1994A BONDS	10,383,121.98	5.734%	0.650%	67,490.29
NRUCFC	14,220,952.84	7.854%	3.243%	461,152.02
Total	$181,075,991.33	100.000%	3.655%	$6,618,306.36

2015 Debt Service Breakout	Interest	Principal	Total
Quarter 1	$ 2,075,715	$ 2,712,316	$ 4,788,031
Quarter 2	$ 1,797,638	$ 2,682,030	$ 4,479,669
Quarter 3	$ 1,816,333	$ 3,570,304	$ 5,386,637
Quarter 4	$ 1,759,173	$ 2,720,855	$ 4,480,028
Totals	$ 7,448,859	$ 11,685,505	$ 19,134,364

1.9

Arizona Electric Power Cooperative, Inc.

Summary of Debt Balances

As of October 1, 2015

NATURE OF OBLIGATION	DATE ISSUED	DATE OF MATURITY	TOTAL AMOUNT OUTSTANDING	FACE RATE	ANNUALIZED INTEREST EXPENSE
FFB DEBT					
NOTE NUMBER:					
HO680	12/31/2008	12/31/2030	$290,002.71	5.8870%	$17,072.46
HO685	12/31/2008	12/31/2030	$2,348,743.67	5.8870%	138,270.54
HO690	12/31/2008	12/31/2030	$601,486.31	5.8870%	35,409.50
HO695	12/31/2008	12/31/2030	$316,582.63	5.8870%	18,637.22
HO700	12/31/2008	12/31/2030	$928,458.21	5.8870%	54,658.33
HO705	12/31/2008	12/31/2030	$207,020.17	5.9400%	12,297.00
HO710	12/31/2008	12/31/2030	$166,609.99	6.2220%	10,366.47
HO715	12/31/2008	12/31/2030	$260,386.77	6.2220%	16,201.26
HO720	12/31/2008	12/31/2031	$922,377.57	6.2590%	57,731.61
HO725	12/31/2008	12/31/2031	$630,251.30	5.9990%	37,808.78
HO730	12/31/2008	12/31/2031	$876,129.09	5.9470%	52,103.40
HO735	12/31/2008	12/31/2031	$1,063,446.46	5.9470%	63,243.16
HO740	12/31/2008	12/31/2031	$984,758.29	5.9470%	58,563.58
HO745	12/31/2008	12/31/2031	$1,034,387.81	5.9990%	62,052.92
HO750	12/31/2008	12/31/2031	$1,155,239.46	6.2590%	72,306.44
HO755	12/31/2008	12/31/2031	$1,106,302.30	5.9990%	66,367.07
HO760	12/31/2008	12/31/2031	$1,919,604.67	6.2590%	120,148.06
HO765	12/31/2008	12/31/2031	$1,352,273.80	5.9990%	81,122.91
HO770	12/31/2008	12/31/2031	$1,114,727.46	5.9470%	66,292.84
HO775	12/31/2008	12/31/2031	$471,963.89	5.9470%	28,067.69
HO780	12/31/2008	12/31/2031	$563,618.53	5.9470%	33,518.39
HO785	12/31/2008	12/31/2032	$542,026.49	6.1250%	33,199.12
HO790	12/31/2008	12/31/2032	$228,027.59	6.1250%	13,966.69
HO795	12/31/2008	12/31/2032	$537,303.62	6.1950%	33,285.96
HO800	12/31/2008	12/31/2032	$268,222.69	6.1950%	16,616.40
HO805	12/31/2008	12/31/2032	$496,656.02	6.1250%	30,420.18
HO810	12/31/2008	12/31/2032	$618,609.21	6.1950%	38,322.84
HO815	12/31/2008	12/31/2032	$1,231,053.99	6.1250%	75,402.06

1.9

Arizona Electric Power Cooperative, Inc.

Summary of Debt Balances

As of October 1, 2015

NATURE OF OBLIGATION	DATE ISSUED	DATE OF MATURITY	TOTAL AMOUNT OUTSTANDING	FACE RATE	ANNUALIZED INTEREST EXPENSE
HO820	12/31/2008	12/31/2032	$621,597.84	6.1950%	38,507.99
HO825	12/31/2008	12/31/2032	$189,752.77	6.1250%	11,622.36
HO830	12/31/2008	12/31/2032	$676,082.15	6.1950%	41,883.29
HO835	12/31/2008	12/31/2032	$579,642.98	6.1250%	35,503.13
HO840	12/31/2008	12/31/2032	$582,712.05	6.1950%	36,099.01
HO845	12/31/2008	12/31/2032	$375,169.52	6.1250%	22,979.13
HO850	12/31/2008	12/31/2032	$236,889.77	6.1950%	14,675.32
HO855	12/31/2008	12/31/2032	$289,486.68	6.1250%	17,731.06
HO860	12/31/2008	12/31/2032	$458,869.87	6.1950%	28,426.99
HO865	12/31/2008	01/03/2034	$326,516.52	6.2370%	20,364.84
HO870	12/31/2008	01/03/2034	$746,237.36	6.2370%	46,542.82
HO875	12/31/2008	01/03/2034	$794,443.05	6.1690%	49,009.19
HO880	12/31/2008	01/03/2034	$1,373,014.22	6.2370%	85,634.90
HO885	12/31/2008	01/03/2034	$855,910.43	6.2370%	53,383.13
HO890	12/31/2008	01/03/2034	$471,900.92	6.2370%	29,432.46
HO895	12/31/2008	01/03/2034	$1,904,736.34	6.2370%	118,798.41
HO900	12/31/2008	01/03/2034	$217,252.96	6.2370%	13,550.07
HO590	01/16/1987	12/31/2020	$0.00	1.4000%	0.00
HO595	04/17/1989	12/31/2020	$0.00	1.2600%	0.00
HO600	07/05/1989	12/31/2020	$836,217.81	8.1180%	67,884.16
HO605	12/27/1989	12/31/2020	$503,560.92	8.0270%	40,420.84
HO610	04/11/1991	12/31/2020	$645,012.18	8.2350%	53,116.75
HO615	06/26/1991	12/31/2020	$1,969,902.70	7.0020%	137,932.59
HO620	12/26/1996	12/31/2020	$1,207,718.11	6.5020%	78,525.83
HO625	10/19/1998	12/31/2020	$1,818,773.86	5.0230%	91,357.01
HO630	05/07/1999	12/31/2020	$986,445.64	5.9200%	58,397.58
HO635	11/15/2002	12/31/2020	$0.00	1.1300%	0.00
HO640	06/07/2004	01/03/2034	$0.00	2.0200%	0.00
HO645	07/30/2004	12/31/2024	$3,796,142.71	4.8800%	185,251.76
HO650	12/03/2004	12/31/2024	$1,741,681.60	4.6350%	80,726.94
HO655	12/29/2004	12/31/2024	$2,953,806.41	4.5230%	133,600.66

1.9

Arizona Electric Power Cooperative, Inc.

Summary of Debt Balances

As of October 1, 2015

NATURE OF OBLIGATION	DATE ISSUED	DATE OF MATURITY	TOTAL AMOUNT OUTSTANDING	FACE RATE	ANNUALIZED INTEREST EXPENSE
HO660	01/28/2005	12/31/2024	$5,836,422.23	4.3910%	256,277.30
HO665	11/01/2005	12/31/2024	$179,643.87	4.6450%	8,344.46
HO670	07/22/2008	01/03/2034	$862,953.00	4.4900%	38,746.59
HO675	07/22/2008	12/31/2024	$498,612.28	4.1840%	20,861.94
HO905	06/10/2009	12/31/2035	$6,873,363.91	4.4170%	303,596.48
HO910	07/08/2009	12/31/2035	$14,601,344.47	4.0110%	585,659.93
HO915	08/10/2009	12/31/2035	$1,080,456.88	4.3650%	47,161.94
HO920	01/22/2010	12/31/2035	$1,115,196.86	4.1020%	45,745.38
HO925	06/03/2010	12/31/2035	$1,028,777.47	3.8160%	39,258.15
HO930	08/03/2010	01/02/2035	$1,897,136.96	3.4670%	65,773.74
HO935	09/02/2010	12/31/2035	$296,895.75	2.9470%	8,749.52
HO940	10/06/2010	01/02/2035	$4,860,698.80	3.0250%	147,036.14
HO945	01/24/2011	12/31/2035	$1,611,295.37	3.9820%	64,161.78
HO950	04/29/2011	12/31/2035	$6,486,562.30	3.8350%	248,759.66
HO955	08/31/2011	01/02/2035	$7,200,508.68	2.6790%	192,901.63
HO960	02/09/2012	01/02/2035	$9,355,087.19	2.3890%	223,493.03
HO965	05/01/2012	01/02/2035	$1,108,802.52	2.3260%	25,790.75
HO970	07/31/2012	01/02/2035	$6,590,786.59	1.8550%	122,259.09
HO975	08/23/2012	01/02/2035	$343,578.17	2.0480%	7,036.48
HO980	10/01/2012	01/02/2035	$34,109.07	2.0000%	682.18
HO985	12/11/2012	01/02/2035	$103,322.60	1.9930%	2,059.22
HO990	12/30/2014	01/03/2034	$3,872,340.32	2.2490%	87,088.93
HO590	01/16/1987	12/31/2020	$806,544.23	1.4000%	11,291.62
HO595	04/17/1989	12/31/2020	$797,212.44	1.2600%	10,044.88
HO635	11/15/2002	12/31/2020	$2,211,456.90	1.1300%	24,989.46
HO640	06/07/2004	01/03/2034	$23,466,172.58	2.0200%	474,016.69
HO995	05/21/2015	01/03/2034	$3,956,887.00	2.3520%	93,065.98
SUB-TOTAL			$156,471,916.51	3.8919%	$6,089,664.05

1.9

Arizona Electric Power Cooperative, Inc.

Summary of Debt Balances

As of October 1, 2015

NATURE OF OBLIGATION	DATE ISSUED	DATE OF MATURITY	TOTAL AMOUNT OUTSTANDING	FACE RATE	ANNUALIZED INTEREST EXPENSE
CFC SERIES 1994A BONDS					
	09/20/1994	09/01/2014		0.6500%	0.00
	09/20/1994	09/01/2015		0.6500%	0.00
	09/20/1994	09/01/2016	876,497.31	0.6500%	5,697.23
	09/20/1994	09/01/2017	943,920.18	0.6500%	6,135.48
	09/20/1994	09/01/2018	1,011,343.05	0.6500%	6,573.73
	09/20/1994	09/01/2019	1,078,765.92	0.6500%	7,011.98
	09/20/1994	09/01/2020	1,146,188.79	0.6500%	7,450.23
	09/20/1994	09/01/2021	1,213,611.66	0.6500%	7,888.48
	09/20/1994	09/01/2022	1,281,034.53	0.6500%	8,326.72
	09/20/1994	09/01/2023	1,348,457.40	0.6500%	8,764.97
	09/20/1994	09/01/2024	1,483,303.14	0.6500%	9,641.47
SUB-TOTAL			$10,383,121.98	0.6500%	$67,490.29
NRUCFC					
9051	09/24/2013	06/30/2024	5,034,006.73	2.9000%	145,986.20
9047	12/20/2011	12/31/2018	7,671,367.56	3.3576%	257,573.84
9048	12/20/2011	12/31/2018	1,515,578.54	3.8000%	57,591.98
SUB-TOTAL			$14,220,952.84	3.2428%	$461,152.02
TOTAL			$181,075,991.33	3.6550%	$6,618,306.36

1.9a
AEPCO
Long-term Debt 10 Year Amortization Schedule

	FFB Debt		CFC Series 1994 A Bonds		CFC 9047		CFC 9048 Equity		CFC 9051	
	Principal	Interest	Principal	Interest	Principal	Interest	Principal	Interest	Principal	Interest
2014 Actual	$ 6,942,768.62	$ 7,589,120.14	$ 809,074.44	$ 78,446.51	$ 2,159,425.75	$ 356,989.35	$ 498,863.01	$ 84,191.57	$ 494,377.77	$167,998.39
2015 Projected	$ 7,893,098.55	$ 6,476,010.80	$ 876,497.31	$ 54,609.15	$ 2,223,128.90	$ 292,106.31	$ 518,091.65	$ 64,962.93	$ 508,871.39	$153,504.77
2016 Projected	$ 8,374,769.88	$ 5,929,002.78	$ 876,497.31	$ 67,490.29	$ 2,292,045.86	$ 222,422.63	$ 538,061.46	$ 44,993.13	$ 523,789.92	$138,586.21
2017 Projected	$ 8,783,094.50	$ 5,520,678.14	$ 943,920.18	$ 61,793.06	$ 2,366,537.34	$ 144,839.90	$ 558,800.99	$ 24,253.58	$ 539,145.82	$123,230.34
2018 Projected	$ 9,156,334.66	$ 5,147,437.98	$ 1,011,343.05	$ 55,657.58	$ 2,450,549.61	$ 52,572.83	$ 287,350.44	$ 4,085.60	$ 554,951.91	$107,424.25
2019 Projected	$ 9,509,346.91	$ 4,794,425.73	$ 1,078,565.92	$ 49,083.85					$ 571,221.38	$ 91,154.78
2020 Projected	$ 9,909,566.98	$ 4,394,205.66	$ 1,146,188.79	$ 42,071.87					$ 587,967.82	$ 74,408.34
2021 Projected	$ 7,848,668.07	$ 4,053,721.10	$ 1,213,611.66	$ 34,621.64					$ 605,205.21	$ 57,170.95
2022 Projected	$ 8,055,204.63	$ 3,712,176.01	$ 1,281,034.53	$ 26,733.17					$ 622,947.96	$ 39,428.20
2023 Projected	$ 8,384,224.88	$ 3,383,155.76	$ 1,348,457.40	$ 18,406.44					$ 641,210.86	$ 21,165.30
2024 Projected	$ 8,725,501.83	$ 3,041,878.81	$ 1,483,303.14	$ 9,641.47						
Total	$93,582,579.51	$54,041,812.91	$12,068,493.73	$498,555.03	$11,491,687.46	$1,068,931.02	$2,401,167.55	$222,486.81	$5,649,690.04	$974,071.53

Based on Debt outstanding at 10/01/2015

1.9b

Arizona Electric Power Cooperative, Inc.

Capital Lease Information

Lessor	Interest Rate	Origination Date	Maturity Date	Lease Amount	Balance 12/31/2014	2015 Amortization
SunPumps Inc 3525 E Main St. Safford, AZ 85546		1/1/2014	12/31/2019	$ 79,810.00	$ 66,601.43	$ 15,962.04

Includes solar rebates received from SSVEC paid over to SunPumps

Lease term includes $1.00 buy-out

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.10 If any of the proceeds from the newly proposed debt will be used to retire existing long-term or short-term debt, identify the specific loans, amounts and anticipated dates for the refunding.

Response: AEPCO does not expect to use any of the proceeds from the proposed debt to retire existing long-term debt. Proceeds may be used to pay down any amounts used under the revolving lines of credit to fund projects identified in this application.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.11 Provide a certificate of resolution from the board of directors authorizing the filing of this application.

Response: A copy of the AEPCO Board resolution is attached.

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 December 10, 2014.

RESOLUTION

WHEREAS, *the Management of Arizona Electric Power Cooperative, Inc. (AEPCO) has recommended and the Board of Directors has previously approved AEPCO's 2015-2017 Construction Work Plan (CWP); and*

WHEREAS, *the Management of AEPCO recommends and the Board of Directors authorizes the funding of projects included in the 2015-2017 CWP through the Rural Utilities Service (RUS), Federal Financing Bank (FFB) loan program; and*

WHEREAS, *it has been determined that the aggregate loan amount for Budget Purpose No. 3 (Generation) eligible projects totals $31,167,000; and*

WHEREAS, *as required by Arizona Statutes, AEPCO is required to obtain the necessary approvals from the Arizona Corporation Commission (ACC) prior to issuing or otherwise acquiring new long term debt;*

NOW, THEREFORE BE IT RESOLVED, *that the Board of Directors hereby authorizes Management to file a financing application with the Rural Utilities Service for a guaranteed Federal Financing Bank loan in the amount of $31,167,000 for Purpose No. 3 (Generation) projects to be used to finance the capital facilities as specified in the 2015-2017 Construction Work Plan; and*

BE IT FURTHER RESOLVED, *that the RUS guaranteed FFB loan shall bear a maturity date not to exceed December 31, 2035; and*

BE IT FURTHER RESOLVED, *that the Board of Directors hereby authorizes Management to seek and otherwise obtain the necessary approvals from the Arizona Corporation Commission to acquire additional long term debt in the aggregate amount of $31,167,000 to fund the Cooperative's 2015-2017 CWP: and*

BE IT FURTHER RESOLVED, *that the Board of Directors hereby authorizes its officers and the Executive Vice President and Chief Executive Officer of Arizona Electric Power Cooperative, Inc., to execute and attest to all necessary papers, documents, and applications related to the loan application; and*

BE IT FURTHER RESOLVED, *that the President of the Board of Directors, any Corporate Officer and/or Executive Vice President and Chief Executive Officer are hereby authorized on behalf of AEPCO, to: (1) execute and deliver from time to time advance requests, maturity extension election notices, prepayment election notices and refinancing notices, in the form of such instruments attached to the note payable to FFB; and (2) to specify information and select the most appropriate and economical repayment option as provided in such instruments; and*

BE IT FURTHER RESOLVED, *that the Board of Directors authorizes the RUS to release the appropriate information and data relating to the application to the FFB and any supplemental lenders as may be necessary in connection with the execution of the loan application or the issuance of debt through the advance requests, maturity extensions, prepayment and/or refinancing notices; and*

BE IT FURTHER RESOLVED, *that each of the following individuals whose signatures appear below, be and hereby, are authorized to enter into and execute, in the name and on the behalf of AEPCO, any such agreements and/or amendments to existing agreements necessary or appropriate to give effect to the purposes and intent of the foregoing Resolutions:*

OFFICER	*NAME*	*SIGNATURE*
President	*C. Brad DeSpain*	C. Brad DeSpain
Executive Vice President and Chief Execuitve Officer	*Patrick F. Ledger*	Patrick F. Ledger
Chief Financial Officer	*Peter F. Scott*	

I, Reuben B. McBride, 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 December 10, 2014.

Reuben B. McBride

Secretary

(seal)

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.12 Provide financial information projecting the Company's estimated financial performance (cash flows, operating income) for each of the next five years, identifying all significant assumptions (e.g., rate increases, customer/sales grow, inflation, etc.).

Response: AEPCO's Long Range Financial Forecast contains confidential material. Accordingly, a copy of the forecast will be provided to Staff upon execution and return of a protective agreement.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.13 If the Company has a revolving line-of-credit facility ("LOC"), provide the following: the execution date, the termination date, the maximum borrowing capacity, the balance for each of the most recent 12 months, the name of the lender, the basis and term for the interest rate charged (e.g., LIBOR plus 2.0 percent), a detailed explanation of any fees other than interest (e.g., a commitment fee) and an explanation of any changes the Company anticipates to the line-of-credit during the next five years.

Response: AEPCO maintains two unsecured, committed revolving line of credit facilities in the amount of $50,000,000 with the CFC and $50,000,000 with CoBank. The CFC facility was executed on June 5, 2014 and has a term of five years with two possible one-year extensions. The CoBank line was executed August 21, 2014 and has a term of five years. This financing was approved in Decision No. 74447 in Docket No. E-01773A-14-0019.

Balance information is provided on the attached schedule. AEPCO intends to continue to use these facilities as liquidity support as well as interim financing. Within the next five years, AEPCO may exercise the CFC extensions (as authorized by the Commission in Decision No. 74447) and may seek to renew the CoBank LOC.

The contact information for CFC is provided in AEPCO's response to data request 1.2. The contact information for CoBank is:

CoBank, ACB
5500 South Quebec St.
Greenwood Village, CO 80111

The remaining requested information is deemed confidential. Accordingly, AEPCO will provide the additional information to Staff upon execution and return of a protective agreement.

1.13

Arizona Electric Power Cooperative, Inc.

Line of Credit Balances by Month

Month	CFC Balance	CoBank Balance
Nov-14	$ -	$ -
Dec-14	$ -	$ -
Jan-15	$ -	$ -
Feb-15	$ -	$ -
Mar-15	$ -	$ -
Apr-15	$ -	$ -
May-15	$ -	$ -
Jun-15	$ 5,000,000.00	$ -
Jul-15	$ -	$ 10,000,000.00
Aug-15	$ -	$ 10,000,000.00
Sep-15	$ -	$ 10,000,000.00
Oct-15	$ -	$ 5,000,000.00

1.14 If applicable, provide the Company's most recent credit agency(ies) financial review(s).

Response: AEPCO does not have a public credit rating at this time.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.15 Provide the Commission decision number and date for the Company's most recent general rate case and state the date of the test year end used in that rate case.

Response: AEPCO's most recent general rate case decision, Decision No. 74173, was issued on October 25, 2013. The test year was the calendar year ended December 31, 2011.

1.16 Identify any additional financing authorizations the Company contemplates seeking from the Commission in the next five years.

Response: AEPCO may file additional financing applications as new CWPs are developed for future periods.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSES TO ARIZONA CORPORATION COMMISSION STAFF'S
STANDARD INITIAL FINANCING DATA REQUESTS
Docket No. E-01773A-15-XXXX
November 13, 2015

1.17 For a financing application by an electric provider in which the funds will be used for projects in a CWP that has not been previously reviewed by the Commission, provide the following information in the spreadsheet provided:

a. Peak Demand (MW) & Energy MWh for the most recent previous five years.
b. Peak Demand (MW) & Energy (MWh) projected for the next five years.
c. Historical System Losses in MWh for the most recent previous five years.
d. Number of Customers for the most recent previous five years by Customer Class.
e. Total System Average Interruption Duration Index (SAIDI) for the most recent previous five years as well as SAIDI by the causes of Power Supplier, Planned, Major Events, and All Other.

Response: See the attached spreadsheets. Please note the customer numbers were derived from AEPCO's Class A Members' Form 7 data.

COMPANY NAME: Arizona Electric Power Cooperative, Inc.

PEAK DEMAND, ENERGY DELIVERED, SYSTEM LOSSES

Year	Peak Demand (MW)	Year/Year % Change	Energy Delivered (MWh)	Year/Year % Change	Losses (MWh)	Losses % Total Energy
5 Year Actual						
2010	586		2803861		74992	0.02604926
2011	521	-11.1%	2453572	-12.5%	77079	0.03045817
2012	536	2.9%	2277773	-7.2%	76499	0.0324937
2013	635	18.5%	2726675	19.7%	68455	0.02449081
2014	676	6.5%	3192218	17.1%	85845	0.02618772
5 Year Forecast						
2015	541	-20.0%	2940281	-7.9%		0
2016	550	1.7%	3088868	5.1%		0
2017	552	0.4%	3113089	0.8%		0
2018	565	2.4%	2895903	-7.0%		0
2019	566	0.2%	2960923	2.2%		0

Actuals from Form 12

Forecast from 2014 Financial Forecast

COMPANY NAME: Arizona Electric Power Cooperative, Inc.

MOST RECENT 5 YEARS AVERAGE ANNUAL CUSTOMER NUMBERS

Year	Total Residential Customers	Total Commercial Customers	Total Industrial Customers	Total Other Customers (a)	Total Customers	Change in # of Cust
2010	127,549	16,267	36	1,588	145,440	
2011	128,209	16,240	38	1,723	146,210	770
2012	128,945	16,334	39	1,482	146,800	590
2013	129,888	16,536	43	1,594	148,061	1,261
2014	131,410	16,674	48	1,332	149,464	1,403

(a) includes irrigation customers

Year Over Year Percent Change

Year	Total Residential Customers	Total Commercial Customers	Total Industrial Customers	Total Other Customers	Total Customers
2010					
2011	0.5%	-0.2%	5.6%	8.5%	0.5%
2012	0.6%	0.6%	2.6%	-14.0%	0.4%
2013	0.7%	1.2%	10.3%	7.6%	0.9%
2014	1.2%	0.8%	11.6%	-16.4%	0.9%

Customer numbers derived from AEPCO's Class A Members' Form 7 data

COMPANY NAME: Arizona Electric Power Cooperative, Inc.

SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI) BY CAUSE

Year	*Power Supplier*	*Planned*	***All Other***	*Total Excluding Major Events*	***Major Events***	**All Events**
2010	0.0	0.0	**0.0**	0.0		**0.0**
2011	0.0	0.0	**0.0**	0.0		**0.0**
2012	0.0	0.0	**0.0**	0.0		**0.0**
2013	0.0	0.0	**0.0**	0.0		**0.0**
2014	0.0	0.0	**0.0**	0.0		**0.0**
Five-Year Average	0.0	0.0	**0.0**	0.0	**0.0**	**0.0**

All units at Apache Station

COMPANY NAME: Arizona Electric Power Cooperative, Inc.

SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI) BY CAUSE

Year	*Power Supplier*	*Planned*	***All Other***	*Total Excluding Major Events*	***Major Events***	**All Events**
2010	0.1	1.3	**19.4**	20.8		**20.8**
2011	0.8	0.3	**16.6**	17.8		**17.8**
2012		0.8	**17.4**	18.3		**18.3**
2013	0.3		**34.6**	34.9		**34.9**
2014	0.0	0.7	**15.1**	15.8		**15.8**
Five-Year Average	0.3	0.6	**20.6**	21.5	**0.0**	**21.5**

Data is for Southwest Transmission Cooperative, Inc.