BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED, AN ELECTRIC COOPERATIVE NONPROFIT MEMBERSHIP CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN.

DOCKET NO. E-01750A-11-0136

STAFF'S NOTICE OF FILING DIRECT TESTIMONY

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission") hereby files the (Public) Direct Testimony (except Cost of Service and Rate Design) of Staff witnesses Crystal S. Brown, Jerry Mendl, Candrea Allen and Margaret "Toby" Little in the above-referenced matter. An unredacted (Confidential) version of Jerry Mendl's Direct Testimony has also been provided under seal to the Commissioners, their Policy Advisors and the assigned Administrative Law Judge.

RESPECTFULLY SUBMITTED this 12th day of January, 2012.

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of the foregoing were filed this
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Phoenix, Arizona 85007

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BEFORE THE ARIZONA CORPORATION COMMISSION

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Chairman
BOB STUMP
Commissioner
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IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED, AN ELECTRIC COOPERATIVE NONPROFIT MEMBERSHIP CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN.	)	DOCKET NO. E-01750A-11-0136

DIRECT

TESTIMONY

OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 12, 2012

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SCHEDULES

EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01750A-11-0136

Mohave Electric Cooperative, Inc. ("Mohave Electric" or "Cooperative") is a certificated Arizona-based non-profit rural electric distribution cooperative. Mohave Electric provides electric service to approximately 38,577 customers within areas of Mohave, Coconino, and Yavapai counties, Arizona.

Mohave Electric proposed a $2,994,231, or 3.94 percent, revenue increase from $76,068,006 to $79,062,237. The proposed revenue requirement would produce an operating margin[1] before interest on long-term debt of $3,605,952 for a 7.50 percent rate of return on an original cost rate base of $48,083,871 and produce a 1.67 times interest earned ratio ("TIER").

Staff recommends a $2,905,709, or 3.82 percent, revenue increase from $76,068,006 to $78,973,715. This recommended revenue requirement would produce an operating margin[2] before interest on long-term debt of $3,550,132 for a 7.38 percent rate of return on an original cost rate base of $48,083,871 and produces a 1.64 TIER.

STAFF RECOMMENDATIONS

1. Staff recommends a revenue requirement of $78,973,715.

2. Staff further recommends that the Cooperative's request to eliminate the nine million dollar cash or cash equivalent reserve requirement ordered in Decision No. 72216, dated March 9, 2011, be approved.

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[1] The term "operating margin" when used in context with Arizona electric distribution cooperatives has the same connotation as operating income. The $3,605,952 amount results in a 7.50 percent rate of return on a $48,083,871 rate base and represents 4.74 percent of the Cooperative's total operating revenue of $76,068,006.

[2] The term "operating margin" when used in context with Arizona electric distribution cooperatives has the same connotation as operating income. The $3,550,132 amount results in a 7.38 percent rate of return on a $48,083,871 rate base and represents 4.67 percent of the Cooperative's total operating revenue of $76,068,006.

INTRODUCTION

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

A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst V.

A. I am responsible for the examination and verification of financial and statistical information included in utility rate applications. In addition, I develop revenue requirements, prepare written reports, testimonies, and schedules that include Staff recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science Degree in Business Administration from the University of Arizona and a Bachelor of Science Degree in Accounting from Arizona State University.

Since joining the Commission in August 1996, I have participated in numerous rate cases and other regulatory proceedings involving electric, gas, water, and wastewater utilities. I have testified on matters involving regulatory accounting and auditing. Additionally, I have attended utility-related seminars sponsored by the National Association of Regulatory Utility Commissioners ("NARUC") on ratemaking and accounting designed to provide continuing and updated education in these areas.

Q. What is the scope of your testimony in this case?

A. I am presenting Staff's analysis and recommendations in the areas of rate base, operating revenues and expenses and revenue requirement regarding Mohave Electric Cooperative, Inc.'s ("Mohave Electric" or "Cooperative") application for a permanent rate increase.

Q. Who else is providing Staff testimony and what issues will they address?

A. Staff witness Jerry Mendl is presenting Staff's base cost of power recommendation. Staff witness Candrea Allen is presenting Staff's recommendation concerning the Cooperative's Rules, Regulations and DSM program. Staff witness Bentley Erdwurm is presenting Staff's rate design recommendations. Staff witness Prem Bahl is presenting Staff's cost of service and engineering analysis and recommendations.

BACKGROUND

Q. Please review the background of this application.

A. Mohave Electric is a certificated Arizona-based non-profit rural electric distribution cooperative. Mohave Electric provides electric service to approximately 38,577 customers within areas of Mohave, Coconino, and Yavapai counties, Arizona.

Mohave Electric filed an application for a permanent rate increase on March 30, 2011. On June 27, 2011, Staff filed a letter declaring the application sufficient. Mohave Electric's current rates were authorized in Decision No. 57172, dated November 29, 1990.

Q. What are the primary reasons for the Cooperative's requested permanent rate increase?

A. The Cooperative states that it experienced an adjusted test year operating loss of $965,385. According to the Cooperative, the primary reasons it filed the application are to enable it to meet operating expenses, repay its financing and make improvements to its system in order to maintain adequate and reliable service within its certificated area.

Q. Is Mohave Electric requesting any other approvals?

A. Yes, Mohave Electric is requesting to eliminate the nine million dollar cash or cash equivalent reserve requirement ordered in Decision No. 72216, dated March 9, 2011.

CONSUMER SERVICES

Q. Please provide a brief history of customer complaints received by the Commission regarding Mohave Electric.

A. Staff reviewed the Commission's records for the period of January 1, 2008 through November 8, 2011, and found 64 complaints. All complaints have been resolved and closed. There were eight opinions opposing the rate increase.

SUMMARY OF PROPOSED REVENUES

Q. Please summarize the Cooperative's filing.

A. The Cooperative proposes total annual revenue of $79,062,237 as shown on Schedule CSB-1. This proposed revenue provides a $2,994,231, or 3.94 percent, revenue increase over adjusted Test Year revenues of $76,068,006. Operating revenue of $79,062,237 would produce an operating margin[3] before interest on long-term debt of $3,605,952 for a 7.50 percent rate of return on an original cost rate base ("OCRB") of $48,083,871 and produces a 1.67 Times Interest Earned Ratio ("TIER").

[3] The term "operating margin" when used in context with Arizona electric distribution cooperatives has the same connotation as operating income. The $3,605,952 amount results in a 7.50 percent rate of return on a $48,083,871 rate base and represents 4.74 percent of the Cooperative's total operating revenue of $76,068,006.

Q. Please summarize Staff's recommended revenue.

A. Staff recommends total annual revenue of $78,973,715 as shown on Schedule CSB-1. This recommended revenue provides a $2,905,709 or 3.82 percent revenue increase over adjusted test year revenues of $76,068,006. Operating revenue of $78,973,715 produces an operating margin[4] before interest on long-term debt of $3,550,132 for a 7.38 percent rate of return on an OCRB of $48,083,871 and produces a 1.64 TIER.

Q. What test year did Mohave Electric utilize in this filing?

A. Mohave Electric's rate filing is based on the twelve months ended December 31, 2009, ("test year"). This test year was approximately 15 months old at the time the Cooperative filed its rate application on March 30, 2011. Subsequently, the Cooperative agreed to provide 2010 data. Since the 2010 data reflected the most recent historical 12-month period, consistent with Commission Rules, and provided Staff with more recent information to perform its analysis, Staff updated the 2009 test year to 2010.

Q. Please summarize the rate base and operating margin recommendations and adjustments addressed in your testimony for Mohave Electric.

A. Staff made no adjustments to rate base. Staff's operating margin adjustments are as follows:

Operating Margin Adjustments

<u>Base Cost of Power Revenue, Purchased Power Cost Adjustor ("PPCA") Revenue and Purchased Power Expense</u> – This adjustment increases revenues as a result of matching the Base Cost of Power Revenue to the Cooperative-proposed purchased power expense,

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[4] The term "operating margin" when used in context with Arizona electric distribution cooperatives has the same connotation as operating income. The $3,550,132 amount results in a 7.38 percent rate of return on a $48,083,871 rate base and represents 4.67 percent of the Cooperative's total operating revenue of $76,068,006.

eliminates the PPCA revenues from operating revenues, and removes ineligible power costs from the Cooperative-proposed purchased power expense.

Administrative and General Revenue and Expense – This adjustment reclassifies certain costs removed from the base cost of power revenue and purchased power expense and reclassifies them to margin revenue and administrative and general expense.

RATE BASE

Fair Value Rate Base

Q. Did the Cooperative prepare a schedule showing the elements of Reconstruction Cost New Rate Base?

A. No, the Cooperative did not. The Cooperative's filing treats the OCRB the same as the fair value rate base.

Rate Base Summary

Q. Please summarize Staff's adjustments to Mohave Electric's rate base shown on Schedule CSB-2.

A. Staff made no adjustments to Mohave Electric's proposed rate base. Staff recommends a rate base of $48,083,871 which is the same as the Cooperative's proposed rate base.

Operating Margin

Operating Margin Summary

Q. What are the results of Staff's analysis of test year revenues, expenses and operating margin?

A. As shown on Schedules CSB-3 and CSB-4, Staff's analysis resulted in test year revenues of $76,068,006, expenses of $75,423,583 and operating margin before interest expense of $644,423.

Operating Margin Adjustment No. 1 – Base Cost of Power Revenue, Purchased Power Cost Adjustor ("PPCA") Revenue, and Purchased Power Expense

Adjustment to Base Cost of Power Revenue and PPCA Revenue

Q. Explain the purpose of the break-out of the total revenue from sales of electricity into components as shown on Schedules CSB-4 and CSB-5.

A. The purpose is to show the portion of base rates revenue that is generated to recover the purchased power cost separately from the portion of base rates revenue that is generated to recover the remaining cost of service components.

Q. What amount is Mohave Electric proposing for Base Cost of PPCA revenue, and third party sales revenue?

A. The Cooperative has proposed base cost of power revenue of approximately $43,074,463[5], PPCA revenue of $15,505,234, and third party sales revenue of $3,222,980 for a total of $61,802,677.

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[5] $43,074,242 base cost of power revenue +221 rounding/reconciling amount = $43,074,463.

Q. For ratemaking purposes, is it appropriate to include monies from the Cooperative's PPCA in operating revenues?

A. No, it is not appropriate. The PPCA revenues are set using a mechanism that is different from that used to set base rates. Further, the PPCA can change outside of a rate case based on over or under collections in the Cooperative's fuel bank.

Q. Does Mohave Electric's base cost of power revenue match its purchased power expense?

A. No. The Cooperative's filing reflects a $43,074,463 test year base cost of power revenue and a $61,802,677 test year purchased power expense.

Q. What is the cause of the mismatch?

A. The Cooperative did not make a pro forma adjustment to its base cost of power revenue to reflect that, on a going forward basis, a larger amount of its proposed purchase power expense will be recovered through the base cost of power rate.

Q. Should Mohave Electric's test year total power revenue equal purchased power expense?

A. Yes. The Cooperative has a purchased power adjustor mechanism that facilitates full recovery of all purchased power costs. The adjustor mechanism ensures that the Cooperative neither over nor under recover purchased power cost. This means that changes in the cost of purchased power do not affect income. The difference between the amount collected from customers and the amount paid to power suppliers for purchased power in any year due to timing differences is reflected on the balance sheet as an asset or liability, not on the income statement.

Failure to recognize equal amounts for the revenue and expense associated with purchased power when an adjustor mechanism is in effect is inconsistent with the United States Department of Agriculture Rural Utility Service Uniform System of Accounts. This mismatch results in a misstatement of income. Therefore, any pro forma adjustment to purchased power expense must be offset by an equal adjustment to total power revenue.

Q. Did Staff make any other adjustments to the base cost of power revenue?

A. Yes. Staff reduced base cost of power revenue by $594,737 in order to match the $594,737 decrease in purchased power expense recommended by Staff witness, Jerry Mendl. Staff's adjustment is shown on Schedule CSB-5, line 8.

Q. Please summarize the Cooperative's total Power Revenue components and Staff's adjustments to Base Cost of Power Revenue?

A. The Cooperative has proposed base cost of power revenue of approximately $43,074,463[6], PPCA revenue of $15,505,234, and third party sales revenue of $3,222,980, for a total of $61,802,677 for Power Revenue.

Staff removed $15,505,234 in PPCA revenues ($61,802,677 - $15,505,234 = $46,297,443) because the PPCA rate is set using a different mechanism and can be changed outside of a rate case; therefore, its inclusion in test year revenue is inappropriate for ratemaking purposes. Staff then increased the base cost of power by $15,505,234 ($46,297,443 + $15,505,234 = $61,802,677) to match the Cooperative-proposed purchased power expense of $61,802,677. Next, Staff decreased the base cost of power revenue by $594,737 to match Staff's proposed purchased power expense of $61,207,940 ($61,802,677 - $594,737 = $61,207,940) as shown on Schedule CSB-5.

[6] $43,074,242 base cost of power revenue +221 rounding/reconciling amount = $43,074,463.

Q. What is Staff's recommendation for total power revenue?

A. Staff is recommending $61,207,940 as shown on Schedule CSB-5.

Adjustment to Purchased Power Expense

Q. What purchased power amount did the Cooperative propose?

A. The Cooperative proposed $61,802,677 for purchased power expense.

Q. Did Staff make any adjustment to purchased power expense?

A. Yes, Staff removed $594,737 in costs that were not purchased power costs as discussed in greater detail by Staff witness, Jerry Mendl. Staff reclassified $562,035 in costs related to labor and consulting. Staff disallowed $32,038 related to lobbying and $664 in unsupported costs for a total of $32,702 as shown on Schedules CSB-4 and CSB-6.

Q. What are the direct revenue and expense effects of Staff's recommendation for a lower purchase power expense than the Cooperative?

A. There is no change to income because purchase power expense and base cost of power revenue both decrease by the same amount.

Q. Does Staff's recommendation for a lower purchased power expense affect the amount of power cost the Cooperative will recover?

A. No. A change in the purchased power expense only affects the amount of power cost recovered through base rates. The Cooperative has an adjustor mechanism that provides for matching recovery with actual purchased power costs.

Q. What is Staff's recommendation for purchased power expense?

A. Staff recommends purchased power expense of $61,207,940.

Operating Margin Adjustment No. 2 – Administrative and General Revenue and Expense

Q. What adjustment did Staff make to administrative and general revenue and expense?

A. Staff reclassified expenses of $562,035[7] that were removed from the base cost of power revenue and purchased power expense. Staff added the amount to both administrative and general revenues and expense as shown on Schedules CSB-3 and CSB-6.

Q. What is Staff's recommendation?

A. Staff recommends increasing margin revenue by $594,737 and administrative and general expense by $562,035 as shown on Schedules CSB-4 and CSB-6.

REVENUE REQUIREMENT

Debt Service Coverage

Q. What are the primary factors considered in determining the Cooperative's revenue requirement?

A. Staff's revenue requirement is primarily driven by the revenues needed to pay the principal and interest on long-term debt, and to meet the minimum debt service coverage ("DSC") ratio required by the National Rural Utilities Cooperative Finance Corporation ("RUS"/"CFC"). Additionally, Staff's revenue requirement provides sufficient cash flow to pay operating expenses and to build equity.

Q. What was the amount of the Cooperative's outstanding long-term debt at the end of the test year, and what was the test year interest expense incurred?

A. At the end of the test year, the Cooperative had $37,450,215 in long-term debt, and it incurred $2,161,308 in interest expense.

[7] Staff removed $594,737 from purchased power expense but reclassified only $562,035.

Q. Would you please briefly define the debt service coverage ratio ("DSC") and the TIER?

A. DSC measures an entity's ability to generate cash flow to pay its debt service obligations (interest and principal) from operating activities. It is calculated by dividing (1) earnings before interest, taxes, and depreciation expense by (2) the principal and interest payments. When the DSC is greater than 1.0, operating cash flow is sufficient to cover debt obligations.

TIER measures the number of times operating income will cover interest on long-term debt. It is calculated by dividing (1) operating margin after interest on long-term debt plus interest on long-term debt by (2) interest on long-term debt. When the TIER is greater than 1.0, operating income is sufficient to cover interest expense.

Q. What are Mohave Electric's DSC and TIER requirements?

A. For the loan agreements Mohave Electric has with the RUS/CFC, the DSC and TIER ratio requirements are 1.25 and 1.5, respectively.

Q. Did Staff calculate the DSC differently than the Cooperative?

A. Yes.

Q. How does Mohave Electric calculate DSC?

A. Mohave Electric uses the DSC calculation prescribed by the RUS/CFC. The RUS/CFC includes revenues derived from activities that are not a part of the Cooperative's core electric retail sales business (i.e. non-operating margin interest revenue and cash capital credit revenue). The RUS/CFC calculation is as follows:

For any calendar year add (1) Operating Margins, (2) Non-Operating Margins-Interest, (3) Interest Expense on long-term debt, (4) Depreciation and Amortization Expense, and (5) cash received from capital credits. Divide the sum so obtained by the sum of all payments of Principal and Interest on long-term debt.

Q. How does Staff's DSC calculation differ from the Cooperative's?

A. Staff's calculation is similar but excludes non-operating revenue from interest and capital credits.

Q. Why does Staff exclude non-operating revenue in its DSC calculation?

A. Non-operating revenue tends to be inconsistent from year to year. Staff's calculation measures the Cooperative's ability to make principal and interest payments based solely on the Cooperative's core operating results. Since operating results are generally more consistent than non-operating results, Staff's calculation provides a more reliable indication of ability to service debt.

Q. What revenue is Staff recommending to satisfy Mohave Electric's DSC and TIER requirements?

A. Staff recommends revenue of $78,973,715 to provide a 1.53 DSC and a 1.64 TIER. Staff's proposed revenue would generate enough cash flow to service the Cooperative's debt and comply with CFC debt coverage requirements, allow for reasonable contingencies, and build equity.

Q. What is Staff's recommended increase over the Staff adjusted test year revenue?

A. Staff's recommended revenue of $78,973,715 is a $2,905,709 (or a 3.82 percent) increase over the Staff adjusted test year revenue of $76,068,006.

Q. Is 3.82 percent representative of the increase to customer bills on average with Staff's recommended revenue requirement?

A. Customer bills are comprised of margin costs and the cost of purchased power. The margin cost portion of customer bills would increase on average by 3.82 percent. The cost of power portion of customer bills reflects, on average, the Cooperative's actual cost of purchased power. The cost of purchased power fluctuates and might result in a different increase or decrease in customers' bills.

Revenues from New Service Charge

Q. What amount of increase did the Cooperative propose for Other Revenues?

A. The Cooperative proposed $256,648 as shown on the Cooperative's Supplemental Schedule A-1.0.

Q. Did the Cooperative propose a new service charge?

A. Yes. The Cooperative proposed a new deferred payment plan service charge of 1.5 percent.

Q. What amount of additional revenue would the implementation of the new service charge generate?

A. Mohave Electric estimates that the new service charge would generate approximately $55,820.

Q. Was the additional revenue reflected in the Mohave Electric's proposed revenue requirement?

A. No, it was not.

Q. Did Staff reflect the additional revenue in Staff's recommended revenue requirement?

A. Yes. The additional revenue is reflected in the Other Revenues account.

REQUEST TO ELIMINATE RESERVE REQUIREMENT

Q. What does the Cooperative request to eliminate?

A. Mohave Electric requests to eliminate the nine million dollar cash or cash equivalent reserve requirement ordered in Decision No. 72216, dated March 9, 2011.

Q. Why was the nine million dollar cash or cash equivalent reserve requirement originally recommended?

A. Decision No. 72216 approved Mohave Electric's request for a $28 million loan. Staff's financial analysis determined that both of the Cooperative's TIER and DSC ratios were less than one. A DSC less than one means that debt service obligations cannot be met by cash generated from operations and that another source of funds is needed to avoid default. Consequently, the nine million dollar cash or cash equivalent reserve requirement was recommended.

Q. Will Staff's recommended revenue requirement provide TIER and DSC ratios greater than one?

A. Yes. Therefore, the nine million dollar cash or cash equivalent reserve requirement is no longer needed.

Q. What is Staff's recommendation concerning the reserve requirement?

A. Staff recommends that the Cooperative's request to eliminate its $9 million reserve requirement be approved.

Q. Does this conclude Staff's direct testimony?

A. Yes, it does.

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION		[A] COMPANY ORIGINAL COST		[B] STAFF ORIGINAL COST
1	Adjusted Operating Margin (Loss) Before Interest on L.T.-Debt	$	611,721	$	644,423
2	Depreciation and Amortization	$	2,239,666	$	2,239,666
3	Income Tax Expense		-		-
4	Long-term Interest Expense	$	2,161,308	$	2,161,308
5a	Principal Repayment	$	1,624,749	$	1,624,749
5b	Interest Income	$	410,049	$	410,049
5c	Cash Capital Credits	$	34,479	$	34,479
6a	**Recommended Increase in Operating Revenue**	$	2,994,231	**$**	**2,905,709**
6b	**Percent Increase (Line 6a / Line 7) - Per Staff**		N/A		**3.82%**
6c	Percent Increase (Line 6a / $76,068,006) - Per Cooperative		3.94%		N/A
7	Adjusted Test Year Operating Revenue	$	76,068,006	$	76,068,006
8	**Recommended Annual Operating Revenue**	$	79,062,237	**$**	**78,973,715**
9a	**Recommended Operating Margin Before Interest on L.T.-Debt**	$	3,605,952	**$**	**3,550,132**
9b	Recommended Operating Margin After Interest on L.T.-Debt	$	1,285,224	$	1,229,404
10a	**Recommended Operating TIER Before Intr on LT Debt(L4+L9a)/L4**		1.67		**1.64**
10b	Operating TIER After Interest on LT Debt(L4+L9b)/L4		1.59		1.57
11a	**Recommended DSC (L2+L3+L9a)/(L4+L5) - Per Staff**		N/A		**1.53**
11b	Recommended DSC - Per Cooperative		1.62		N/A
12	**Adjusted Rate Base**	$	48,083,871	**$**	**48,083,871**
13	Rate of Return (L9a / L12)		7.50%		7.38%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Staff Schedule CSB-4, Testimony

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		[A] COOPERATIVE TEST YEAR UPDATED TO 2010	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Plant in Service	$ 88,890,934	$ -	$ 88,890,934
2	Less: Acc Depreciation & Amortization	(35,708,314)	-	(35,708,314)
3	Net Plant in Service	$ 53,182,620	$ -	$ 53,182,620
	LESS:			
4	Consumer Deposits	$ (2,494,774)	$ -	$ (2,494,774)
5	Consumer Construction Advances	$ (4,596,854)	$ -	$ (4,596,854)
6	Consumer Energy Prepayments	$ (1,322,966)	$ -	$ (1,322,966)
7	Total	(8,414,594)	-	(8,414,594)
	ADD:			
8	Cash Working Capital	$ -	$ -	$ -
9	Materials and Supplies	$ 2,087,854	$ -	$ 2,087,854
10	Prepayments	$ 1,227,991	$ -	$ 1,227,991
11	Total	$ 3,315,845	$ -	$ 3,315,845
12	**Total Rate Base**	$ 48,083,871	$ -	$ 48,083,871

References:
Column [A], Cooperative Schedule B-1
Column [B]:
Column [C]: Column [A] + Column [B]

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Schedule CSB-3

OPERATING MARGIN - TEST YEAR AND STAFF RECOMMENDED

Line No.	DESCRIPTION	[A] COOPERATIVE TEST YEAR UPDATED TO 2010	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF RECOMMENDED CHANGES	[E] STAFF RECOMMENDED
	REVENUES:					
1	Margin Revenue (Excludes BCOP Rev & PPCA Rev)	$ 13,658,430	$ 594,737	$ 14,253,167	$ 2,593,241	$ 16,846,408
2						
3	Base Cost of Power ("BCOP") Revenue	$ 43,074,242	$ 14,910,497	$ 57,984,739	$ -	$ 57,984,739
4	Purchased Power Cost Adjustor ("PPCA") Revenue	15,505,234	(15,505,234)	-	-	-
5	Rounding/Reconciling Amount	221	-	221	-	221
6	Subtotal	$ 58,579,697	$ (594,737)	$ 57,984,960	$ -	$ 57,984,960
7	Off System Sales (Third Party Sales)	3,222,980	-	3,222,980	-	3,222,980
8	Subtotal	$ 61,802,677	$ (594,737)	$ 61,207,940	$ -	$ 61,207,940
9						
10	Other Revenues	$ 606,899	$ -	$ 606,899	$ 312,468	$ 919,367
13	**Total Revenues (L1 + L8 + L10)**	**$ 76,068,006**	**$ 0**	**$ 76,068,006**	**$ 2,905,709**	**$ 78,973,715**
14						
15	EXPENSES:					
16	Purchased Power	$ 61,802,677	$ (594,737)	$ 61,207,940	$ -	$ 61,207,940
17	Sub Transmission O&M	169,400	-	169,400	-	169,400
18	Distribution - Operations	2,773,698	-	2,773,698	-	2,773,698
19	Distribution - Maintenance	1,194,657	-	1,194,657	-	1,194,657
20	Consumer Accounting	2,227,246	-	2,227,246	-	2,227,246
21	Customer Service	196,226	-	196,226	-	196,226
22	Sales	96,252	-	96,252	-	96,252
23	Administrative and General	4,756,463	562,035	5,318,498	-	5,318,498
24	Depreciation and Amortization	2,239,666	-	2,239,666	-	2,239,666
25	Taxes	-	-	-	-	-
26	Total Operating Expenses	$ 75,456,285	$ (32,702)	$ 75,423,583	$ -	$ 75,423,583
27						
28	Operating Margin Before Interest on L.T.- Debt	$ 611,721	$ 32,702	$ 644,423	$ 2,905,709	$ 3,550,132
29						
30	INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS					
31	Interest on Long-term Debt	$ 2,161,308	$ -	$ 2,161,308	$ -	$ 2,161,308
32	Interest - Other	$ 142,396	$ -	$ 142,396	$ -	$ 142,396
33	Other Dedcutions	$ 17,024	$ -	$ 17,024	$ -	$ 17,024
34	Total Interest & Other Deductions	$ 2,320,728	$ -	$ 2,320,728	$ -	$ 2,320,728
35						
36	MARGINS (LOSS) AFTER INTEREST EXPENSE	$ (1,709,007)	$ 32,702	$ (1,676,305)	$ 2,905,709	$ 1,229,404
37						
38	NON-OPERATING MARGINS					
39	Interest Income	$ 410,049	$ -	$ 410,049	$ -	$ 410,049
	Gain(Loss) Equity Investments	$ 110,369	$ -	$ 110,369	$ -	$ 110,369
40	Other Margins	$ (32,307)	$ -	$ (32,307)	$ -	$ (32,307)
41	G&T Capital Credits	$ 3,509,969	$ -	$ 3,509,969	$ -	$ 3,509,969
42	Other Capital Credits	$ 107,687	$ -	$ 107,687	$ -	$ 107,687
43	Total Non-Operating Margins	$ 4,105,767	$ -	$ 4,105,767	$ -	$ 4,105,767
44						
45	EXTRAORDINARY ITEMS	$ -	$ -	$ -	$ -	$ -
46						
47	NET MARGINS (LOSS)	$ 2,396,760	$ 32,702	$ 2,429,462	$ 2,905,709	$ 5,335,171
48						
49						
50	References:					
51	Column (A): Cooperative Schedule A					
52	Column (B): Schedule CSB-4					
53	Column (C): Column (A) + Column (B)					
54	Column (D): Schedule CSB-1; Testimony					
55	Column (E): Column (C) + Column (D)					

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

Schedule CSB-4

SUMMARY OF OPERATING MARGIN ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] PER COOPERATIVE	[B] ADJ #1 Power Revenue, PPCA Revenue, & Purchased Pwr Exp Ref: Sch CSB-5	[C] ADJ #2 Administrative & General Rev & Exp Ref: Sch CSB-6	[D] STAFF ADJUSTED
	REVENUES:				
1	Margin Revenue (Excludes BCOP Rev & PPCA Rev)	$ 13,658,430	$ -	$ 594,737	$ 14,253,167
2					
3	Base Cost of Power ("BCOP") Revenue	$ 43,074,242	$ 14,910,497	$ -	$ 57,984,739
4	Purchased Power Cost Adjustor ("PPCA") Revenue	15,505,234	(15,505,234)	-	-
5	Rounding/Reconciling Amount	221	-	-	221
6	Subtotal	$ 58,579,697	$ (594,737)	$ -	$ 57,984,960
7	Off System Sales (Third Party Sales)	3,222,980	-	-	3,222,980
8	Subtotal	$ 61,802,677	$ (594,737)	$ -	$ 61,207,940
9					
10	Other Revenues	$ 606,899	$ -	$ -	$ 606,899
11					
12	**Total Revenues (L1 + L8 + L10)**	**$ 76,068,006**	**$ (594,737)**	**$ 594,737**	**$ 76,068,006**
13					
14	***OPERATING EXPENSES:***				
15	Purchased Power	$ 61,802,677	$ (594,737)	$ -	$ 61,207,940
16	SubTransmission Operation and Maintenance	169,400	-	-	169,400
17	Distribution - Operations	2,773,698	-		2,773,698
18	Distribution - Maintenance	1,194,657	-	-	1,194,657
19	Consumer Accounting	2,227,246	-	-	2,227,246
20	Customer Service	196,226	-	-	196,226
21	Sales	96,252	-	-	96,252
22	Administrative and General	4,756,463	-	562,035	5,318,498
23	Depreciation and Amortization	2,239,666	-	-	2,239,666
24	Taxes	-	-	-	-
25	**Total Operating Expenses**	$ 75,456,285	$ (594,737)	$ 562,035	$ 75,423,583
26					
27	**Operating Margin Before Interest on L.T.- Debt**	**$ 611,721**	**$ -**	**$ 32,702**	**$ 644,423**
28					
29	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***				
30	Interest on Long-term Debt	$ 2,161,308	$ -	$ -	$ 2,161,308
31	Interest - Other	142,396	-	-	142,396
32	Other Dedcutions	17,024	-	-	17,024
33	**Total Interest & Other Deductions**	$ 2,320,728	$ -	$ -	$ 2,320,728
34					
35	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	**$ (1,709,007)**	**$ -**	**$ 32,702**	**$ (1,676,305)**
36					
37	***NON-OPERATING MARGINS***				
38	Interest Income	$ 410,049	$ -	$ -	$ 410,049
	Gain(Loss) Equity Investments	110,369	-	-	110,369
39	Other Margins	(32,307)			(32,307)
40	G&T Capital Credits	3,509,969			3,509,969
41	Other Capital Credits	107,687	-	-	107,687
42	**Total Non-Operating Margins**	$ 4,105,767	$ -	$ -	$ 4,105,767
43					
44	***EXTRAORDINARY ITEMS***	$ -	-	-	$ -
45					
46	***NET MARGINS (LOSS)***	$ 2,396,760	$ -	$ 32,702	$ 2,429,462

Mohave Electric Cooperative, Inc. **Schedule CSB-5**
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

OPERATING MARGIN ADJUSTMENT NO. 1 - POWER REVENUE, PURCHASED POWER COST ADJUSTOR REVENUE, & PURCHASED POWER EXPENSE

LINE NO.	DESCRIPTION	[A] COOPERATIVE AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED	
1	*Revenue*				
2	Base Cost of Power ("BCOP") Revenue	$ 43,074,242	$ 0	$ 43,074,242	From Line 39
3	Purchased Power Cost Adjustor ("PPCA") Rev	15,505,234	(15,505,234)	-	From Coop Suppl Sch A-1
4	Rounding/Reconciling Amount	221	-	221	
5	**Subtotal BCOP Revenue & PPCA Revenue**	**$ 58,579,697**	**$ (15,505,234)**	**$ 43,074,463**	
6					
7	Staff Recommended Increase To BCOP Rev	-	15,505,234	15,505,234	
8	Staff Recommended Decrease To BCOP Rev	-	(594,737)	(594,737)	From Line 25
9	**Subtotal Revenue**	**$ -**	**$ 14,910,497**	**$ 14,910,497**	
10					
11	Off System Sales (Third Party Sales)	3,222,980	-	3,222,980	From Coop Suppl Sch A-5
12	**Total Revenue**	**$ 61,802,677**	**$ (594,737)**	**$ 61,207,940**	
13					
14	*Expenses*				
15	Purchased Power	$ 61,802,677	$ -	$ 61,802,677	
16					
17	To Remove In House Labor & Benefits	$ -	(120,042)	(120,042)	From JEM-6, P.2
18	To Remove Legal Services	$ -	(335,233)	(335,233)	From JEM-6, P.2
19	To Remove Lobbying Costs	$ -	(32,038)	(32,038)	From JEM-6, P.2
20	To Remove Costs to Prepare Fuel Bank Reports	$ -	(23,015)	(23,015)	From JEM-6, P.2
21	To Remove Consulting Costs	$ -	(83,745)	(83,745)	From JEM-6, P.2
22	To Remove Unsupported Costs	$ -	(664)	(664)	From JEM-6, P.2
23	Subtotal Expenses	-	(594,737)	(594,737)	
24					
25	**Total Expenses**	**$ 61,802,677**	**$ (594,737)**	**$ 61,207,940**	
26					
27	**Operating Margin (Line 18 - Line 30)**	**$ (0)**	**$ 0**	**$ -**	
28					
29		kWh's Subject		kWh's Subject	
30		to PPA in TY	Adjustment	to PPA in TY	
31	Residential Sales	364,970,959	-	364,970,959	
32	Irrigation Sales	4,302,352	-	4,302,352	
33	Small Commercial	113,810,903	-	113,810,903	
34	Large Commercial	171,559,418	-	171,559,418	
35	Lighting	0	-	0	
36	AES Sales	0	-	0	
37	Test Year Sales (In kWhs) subject to PPA	654,643,632	-	654,643,632	
38	Multiplied by: Base Cost of Power per kWh	0.065798000	-	0.065798000	
39	Total Base Cost of Power	$ 43,074,242	$ -	$ 43,074,242	

References:

Column A: Cooperative Supplemental Schedule A-1
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF)
MOHAVE ELECTRIC COOPERATIVE, INC. FOR)
A DETERMINATION OF THE FAIR VALUE OF)
ITS PROPERTY FOR RATE MAKING PRUPOSES,)
TO FIX A JUST AND REASONABLE RETURN)
AND TO APPROVE RATES DESIGNED TO)
DEVELOP SUCH A RETURN)

DOCKET NO. E-01750A-11-0136

PUBLIC

DIRECT

TESTIMONY

OF

JERRY MENDL

ON BEHALF OF COMMISSION STAFF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 12, 2012

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EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01750A-11-0136

The Arizona Corporation Commission ("ACC") secured the services of MSB Energy Associates, Inc. ("MSB"), to evaluate Mohave Electric Cooperative, Inc. ("MEC") power purchases made since July 25, 2001. The purpose of the review is:

- To evaluate MEC's procurement process for power purchases since MEC became a partial requirements customer of AEPCO, identify deficiencies and make recommendations to correct them;

- To determine the prudence of purchases made by MEC since MEC became a partial requirements customer of AEPCO, and make recommendations regarding the prudence of costs allowed for recovery;

- Make recommendations to improve the adjustor mechanism, if necessary and

- Determine the base cost of power.

Conclusions Regarding MEC's Power Procurement Process

Staff concludes that MEC's power procurement process, including MEC's organization and power planning and procurement approaches and policies, are reasonable and appropriate as they pertain to 2010. However, MEC did not provide the information necessary to assess MEC's power procurement process prior to 2010.

Staff recommends that the Commission:

1. Determine that MEC's policies of power supply planning and implementation as being implemented in 2010 are reasonable and appropriate, except for the limit on spot market power purchased.

2. Direct MEC to reconsider the limit on power purchased from the spot market to ensure that full advantage can be taken of lower costs, especially in the future when MEC needs to procure greater amounts of supplemental power and when spot market prices are relatively low and stable.

3. Determine that it is inconclusive whether MEC's policies of power supply planning and implementation being implemented prior to 2010 are reasonable and appropriate.

Conclusions Regarding the Prudence of MEC's Power Purchases

Staff concludes that MEC included several ineligible costs in its purchased power cost subject to the purchased power cost adjustor in 2010, requiring adjustments in both the test year and in the purchased power bank balance. MEC also failed to provide adequate documentation to justify part of its purchased power costs in 2008 and any documentation to justify its purchased power costs in the July 25, 2001 through December 31, 2006 period. These undocumented costs require adjustments in the purchased power bank balance. MEC began purchasing power from AEPCO under rates that went into effect on January 1, 2011. Those rates may affect dispatch and alter future costs.

Staff recommends that the Commission:

1. Reaffirm that for purposes of the purchased power adjustor, purchased power include only the actual costs of purchased power and associated transmission and reject MEC's unilateral attempt to include ineligible costs.

2. Remove from the 2010 base revenues those costs ineligible for purchased power adjustor treatment that MEC included as purchased power costs in 2010, namely in-house labor costs, consulting costs and legal costs associated with planning and procurement of purchased power.

3. Reduce MEC's purchased power bank balance by $594,737.45 to adjust for the inclusion of these ineligible costs.

4. Determine that the actual eligible purchased power costs were adequately documented in 2007, 2009 and 2010.

5. Disallow MEC's undocumented claim of purchased power expenses of $163,221.69 in 2008, and reduce MEC's purchased power bank balance by that amount.

6. Determine that MEC's actual purchased power costs, adjusted to remove the ineligible and undocumented costs, are prudent and reasonable for 2007-2010.

7. Determine that MEC's objection to providing information prior to 2007 made it impossible to assess whether purchased power costs between July 25, 2001 and December 31, 2006 were prudent and reasonable.

8. Impose a prudence adjustment of $1.946 million (equal to 1% of MEC's purchased power costs between July 25, 2001 and December 31, 2006) and reduce MEC's purchased power bank balance by that amount.

9. Require MEC to file its next rate case no later than April 1, 2016, using a 2015 test year to ensure the purchased power cost data and supporting information remains fresh. MEC may file sooner if necessary.

10. Acknowledge that MEC's selection and management of Western to provide critical services regarding block power and market purchases and sales are prudent and reasonable.

Conclusions Regarding Improvements to MEC's Purchased Power Adjustor

Staff concludes that MEC should be required to file its next rate case no later than April 1, 2016, using a 2015 test year, for prudence review in order to keep information fresh and adjustments current. In addition, Staff concludes that MEC should use the margins on power sales for resale to offset the purchased power costs and be run through the purchased power cost adjustor mechanism.

Staff recommends that the Commission:

1. Revise MEC's purchased power adjustor mechanism to use margins on third party sales to offset purchased power costs.

2. Subtract total revenues from third party sales from total cost of purchased power, including power for third party sales, to determine new purchased power costs.

3. Require MEC to file its next rate case no later than April 1, 2016, using a 2015 test year. MEC may file sooner if necessary.

Conclusions Regarding the Base Purchased Power Cost and Purchased Power Bank Balance

Staff concludes that the Commission should set the Base Purchased Power Cost at \$0.087701/kWh. Staff concludes that the Commission should adjust the purchased power bank balance to credit ratepayers with \$2.704 million.

Staff recommends that the Commission:

1. Adopt a base purchased power cost per kWh of \$0.087701/kWh.

2. Adjust the bank balance to credit the ratepayers with \$2.704 million, consisting of \$594,737 of ineligible costs in 2010, \$163,222 of undocumented costs in 2008, and \$1.946 million for undocumented purchased power costs in 2001-2006.

3. Direct MEC to adjust the bank balance for any ineligible costs that may have been recovered through the purchased power cost adjustor after December 31, 2010.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Jerry E. Mendl. I am the President of MSB Energy Associates, Inc. ("MSB"). My business address is MSB Energy Associates, Inc., 1800 Parmenter Street, Suite 204, Middleton, Wisconsin 53562.

Q. Does exhibit JEM-1 summarize your qualifications?

A. Yes.

Q. What is the purpose of your testimony?

A. I am appearing on behalf of the Arizona Corporation Commission - Utilities Division Staff to address the prudence of Mohave Electric Cooperative, Inc.'s ("MEC" or "the Cooperative") electric power procurement practices since July 25, 2001, the date that MEC converted from full requirements to partial requirements service from Arizona Electric Power Cooperative, Inc. ("AEPCO"). I was charged with the following tasks:

1. To evaluate MEC's procurement process for power purchases since MEC became a partial requirements customer of AEPCO (Addressed in Section 1of my testimony);
2. To identify any deficiencies in MEC's power procurement process and make recommendations to correct those deficiencies (Section 1);
3. To determine the prudence of purchases made by MEC since MEC became a partial requirements customer of AEPCO (Section 2);
4. To make recommendations regarding the prudence of costs allowed for recovery (Section 2);
5. Make any necessary recommendations to improve the adjustor mechanism (Section 3); and
6. Determine the base cost of power (Section 4).

Q. How did Staff conduct its analysis?

A. Staff compiled information primarily through discovery regarding MEC's power procurement procedures and its application of the purchased power cost adjustor. The purpose was to determine whether MEC's organization and power procurement procedures are likely to result in lowest power costs in a changing electricity market. Does MEC: i) regularly review and evaluate all power supply options ii) select reasonable power supply options and iii) modify its plans when circumstances warrant?

In addition to assessing whether MEC had reasonable power procurement procedures in place, Staff also assessed how MEC's purchased power prices compared to the market electricity prices. The purpose was to determine whether MEC was purchasing power at, above or below market prices. Market prices are a reasonable benchmark for prices that would be deemed prudent. This provides insight on how well MEC's power procurement procedures are working – not only whether reasonable organization and procedures exist but also how they are implemented.

Staff looked at both the procurement procedures and market price benchmark for the 2010 test year. This is the most current historical year for which information is available and is a reasonable indicator of expectations for the future. Staff assessed the prudence of MEC's 2010 purchased power costs, identified adjustments to the revenue requirement for purchased power and used that to determine the base purchased power costs.

Finally, Staff assessed the procurement procedures and market price benchmarks to assess whether the purchased power costs for the rest of the 2001-2010 prudence evaluation period were prudent.

SECTION 1: MEC'S PROCUREMENT PROCESS FOR POWER PURCHASES

Q. What elements should the Commission consider in determining whether MEC's power procurement process is appropriate?

A. The purchased power procurement process comprises institutional and implementation factors. Institutional factors pertain to the organizational structure as it applies to power planning and purchases. Implementation factors focus on the development and execution of appropriate procedures for procuring purchased power.

CRITERIA FOR STRUCTURE AND POWER PROCUREMENT PROCEDURES

Q. What elements should the Commission consider in determining whether MEC is appropriately organized to procure power efficiently and economicially?

A. An appropriate structure should clearly define who has the authority to make decisions about power supplies and purchases. These decisions should include integrated resource planning decisions to determine whether MEC should build or purchase power plants, initiate demand response programs, initiate energy efficiency programs, purchase power from designated power plants, purchase power from the regional spot market, or some combination of these resource options. These decisions will also encompass the volumes of each resource to be acquired, based on need, cost, reliability and risk factors.

An appropriate structure will also clearly indicate the limits on that authority. It may be appropriate for low cost, low volume, low risk resource acquisitions to be addressed at lower levels in the organization, with increasingly higher levels of approval required as the decisions increase in terms of potential impacts.

An appropriate structure will also provide checks and balances to ensure that no single individual has excessive authority and to ensure that potential abuses would be discovered on a timely basis.

Q. What elements should the Commission consider in determining whether MEC has implemented appropriate power procurement procedures?

A. Appropriate implementation of power procurement starts with a well-defined statement of objectives. To achieve these objectives, power procurement procedures ideally should be formally written and documented. Ideally, top-level management should adopt these written formal procedures to ensure that the procurement procedures are given high priority by those who are responsible for implementing them. At a minimum, the procedures, even if not formally adopted by top-management, should be written to provide guidance to and a benchmark for measuring the performance of those responsible for procuring power.

Appropriate implementation of power procurement also requires that the power procurement procedures are communicated to those employees responsible for implementing them. To ensure that all relevant employees are aware of the power procurement procedures, the Cooperative should establish training programs, internal communications, job performance criteria and job performance evaluations.

A method to systematically evaluate progress and results is a key element of an appropriately implemented power procurement procedure. This mechanism should monitor the results of the chosen power procurement approach and compare them to the results had other approaches been used. This mechanism should identify opportunities for improvement and stimulate the Cooperative to be open to changing procedures to improve power procurement performance.

Finally, the power procurement procedure should include a mechanism to update the procedure to incorporate improvements and mitigate deficiencies identified in the monitoring phase. This feedback loop is an important feature of an appropriately implemented power procurement procedure. The updating phase creates the expectation that the Cooperative will change its power procurement procedures when conditions warrant (as identified in the monitoring phase).

ASSESSMENT OF STRUCTURE AND PROCEDURES

Q. What has Staff done to evaluate MEC's organization and implementation of its purchased power procurement process?

A. Staff developed a substantial set of data requests addressing these topics and reviewed responses from MEC. Staff analyzed the responses in the context of the criteria for institutional and implementation factors set forth above.

Q. In Staff's opinion, are MEC's organizational structure and power procurement procedures, as both existed in 2010, adequate and appropriate?

A. Yes, Staff concludes that in 2010 MEC met the criteria that Staff set forth above. In converting from an All Requirements Member to a Partial Requirements Member in 2001, MEC took on additional responsibilities for preparing its own load forecasts; for identifying, evaluating, and implementing resources to serve those demands; and for scheduling and dispatching available resources to optimize day-to-day operations. Nine years after the conversion, MEC has a well-developed, evolved and documented approach in place. Nonetheless, Staff recommends that MEC reconsider one of its general planning criteria because it could unnecessarily limit MEC's access to lower cost power supplies in the future.

Q. Why did Staff conclude that MEC's organizational structure and power procurement procedures were adequate and appropriate for 2010?

A. MEC has a well-conceived organizational structure for power supply planning and power procurement. It has written procedures approved at the highest levels of management that address the criteria Staff set forth above. In response to Staff's third data request, MEC prepared a narrative discussion to accompany the answers to specific questions. The narrative response sets out the fundamentals of MEC's planning process, especially laying out the relationships between MEC and AEPCO (which supplies the majority of the power MEC purchases) and Western Power Administration and, in particular, the Desert Southwest Energy Management and Marketing Office ("Western") (which provides services to meet MEC's loads in a manner to minimize costs and to assess the opportunity to sell MEC's excess to the market). It also lays out the roles of Mohave's staff, consultants and Western in preparing load forecasts; identifying, evaluating and implementing resource options; and day-to-day scheduling and dispatching resources. The narrative response is attached as Exhibit JEM-2 CONFIDENTIAL.

MEC also attached its written "Policy of Power Supply Planning and Implementation" in response to Data Request JM-3.8. This document lays out the responsibilities, authorities and procedures of the MEC Board, MEC management, MEC staff, MEC consultants, AEPCO and Western. It also sets out planning objectives, monitoring and feedback to improve the planning and power procurement process, and reporting requirements. MEC's "Policy of Power Supply Planning and Implementation," is attached as Exhibit JEM-3 CONFIDENTIAL. This policy was accepted by MEC's Board on June 18, 2009.

Each criterion that Staff raised has been satisfied for 2010 in the documentation provided by MEC. The following is a reference to the section of MEC's procurement policy that addresses each criterion:

- Clearly define who has the authority to make decisions about power supplies and purchases. MEC has defined the decision-making authority, primarily at the CEO level, with required reporting to the Board. For some major decisions, such as building or purchasing power plants, the Board is ultimately responsible for decisions. Pursuant to its agreement with Western, Western has been assigned specified duties. This is addressed in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, especially in Sections I, II and III and in response to Staff data request JM-3.28 (attached as Exhibit JEM-4).

- Clearly indicate the limits on that authority. This is adequately laid out in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in Section III.

- Provide checks and balances to ensure that no single individual has excessive authority and to ensure that potential abuses would be discovered on a timely basis. This is adequately laid out in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in paragraphs 7-9 in the Risk section on page 5 of the policy and in Section IV.

- Well-defined statement of objectives. MEC has described the planning objectives in the narrative and attachments to the narrative and in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, especially in Sections II and III.

- Written and documented formal power procurement procedures adopted by top-level management. MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in its entirety is accepted by the Board and generally directs the CEO to implement the policies and procedures. The policies are written and adopted and enforced at the highest levels.

- Communication of power procurement procedures to those employees responsible for implementing them. This is adequately laid out in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in Section IV.

- Method to systematically evaluate progress and results to identify opportunities for improving power procurement performance. This is adequately laid out in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in Section V.

- Mechanism to update the procedure to incorporate improvements and mitigate deficiencies identified in the monitoring phase, the expectation that MEC will change its power procurement procedures when conditions warrant. This is adequately laid out in MEC's "Policy of Power Supply Planning and Implementation," Exhibit JEM-3 CONFIDENTIAL, in Section VI.

In addition, the Cooperative Board specified in more depth the analyses and information it requires from the CEO and MEC management. It also directed Management to advise the Board at least annually, or more frequently if appropriate, regarding these issues and analyses. See the Exhibits attached to MEC's "Policy of Power Supply Planning and Implementation" (beginning at page 15 of the policy document, Exhibit JEM-3 CONFIDENTIAL). The Board also specified a list of questions regarding "policy parameters of responsibility in implementation and oversight" (pages 19-20 of MEC's policy document, Exhibit JEM-3 CONFIDENTIAL) the answers to which are to be included in the Management's annual, or more frequent, report to the Board.

All of these actions by MEC and its Board indicate that MEC has a well-thought out, well-documented, comprehensive power planning and procurement process that is approved at the highest levels in place in 2010. It fulfils the criteria Staff has previously set forth.

Q. Staff concludes that MEC has appropriate organization and power procurement procedures for 2010. What conclusions has Staff reached regarding MEC's organization and power procurement procedures since MEC became a partial requirements member in July 2001?

A. Staff cannot conclude that MEC's organization and power procurement procedures were appropriate prior to 2010. Staff was unable to obtain the information needed to perform that assessment. Staff requested information concerning the evolution of MEC's organization and power procurement in the Staff's Third Data Request. MEC responded by objecting to providing information prior to 2007. In MEC's narrative (Exhibit JEM-2 CONFIDENTIAL, page 1), MEC states:

> As a result, review of Mohave power purchasing between 2001 and 2008 has little or no relevance to the test year and the projected conditions – the only periods relevant to the current rate proceeding. The foregoing, coupled with the burdensome nature on Mohave of requesting it to review a decade of records, back to 2001, resulted in Mohave objecting to data requests seeking information prior to 2007.

In response to specific questions regarding MEC's organization and power procurement procedures, MEC's responses often suggested that the guiding principles reflected in the 2010 power supply planning and implementation process have not changed since MEC became a Partial Requirements Member in 2001. However, MEC's responses also suggested that its 2010 approach was the result of continuous evolution. Exhibit JEM-5 consists of MEC's responses to Staff Data Requests JM-3.18, 3.19, 3.20, 3.27, 3.29, 3.30 and 3.31. Thus it is impossible for Staff to conclude with any certainty the nature of the organization and procurement process prior to 2010. Staff suspects that it has only recently reached its current levels of sophistication.

Q. Since Staff did not receive any documentation of MEC's organization and procurement policies prior to 2010, why does Staff think that the 2010 approaches are a recent development?

A. There are three reasons. First, the 2010 power procurement policy was not accepted by the Board until June 18, 2010, based on a draft produced in April 2010. See Exhibit JEM-12 CONFIDENTIAL, page 1. The April 2010 draft addressed many points that were raised in the context of the Commission's review of the Sulphur Springs Valley Electric Cooperative's ("SSVEC") performance after becoming a Partial Requirements Member in 2007. Many of the questions and issues addressed in MEC's "Policy of Power Supply Planning and Implementation" are verbatim copies of the Staff data requests in the SSVEC case which were proffered in December 2008 and in the subsequent Staff testimony filed in February 2009. Thus, it appears that some of MEC's current organizational and procedural elements were identified in the SSVEC case a few months earlier.

Second, MEC indicates that there had not been a formal written policy statement when MEC became a Partial Requirements Member (See MEC's response to JM-3.19, which is attached in Exhibit JEM-5). Having a formal written policy provides clear guidance to personnel implementing the policy and creates more reliable benchmark by which to assess performance. Lacking a written policy, Staff would find MEC's power planning and procurement approach problematic.

Third, since MEC agreed to provide information covering the 2007-2010 time frame, it would have provided a written policy and documentation that Staff requested, to the extent that it existed after January 1, 2007. Staff's questions typically requested a description of the current practice, the practice as it existed when MEC became a Partial Requirements

Member in 2001, and any updates or amendments Mohave made between July 2001 and the present. See for example Staff Data Request JM-3.20, attached in Exhibit JEM-5.

These facts lead Staff to believe that prior to June 2009, MEC did not have a documented power planning and procurement policy or procedure. Staff commends MEC for upgrading its policies and procedures regarding power planning and procurement in 2009, to be fully in effect during 2010. However, Staff is unable to determine whether MEC's policies and procedures were adequate prior to 2010, though there is evidence to suggest that they were not written or documented from mid-2001 through mid-2009.

Q. Earlier in Staff's testimony, Staff stated that MEC should reconsider one of its general planning criteria because it could unnecessarily limit MEC's access to lower cost power supplies in the future. Please explain.

A. MEC's power supply plans include purchasing block power and spot market power for the summer months to supplement its available supplies from AEPCO. One of the criteria is to limit the amount of power from the spot market to no more than [redacted] of Mohave's monthly load. Its purpose is to limit the economic risk to MEC of exposure to volatile spot market prices. See the narrative, Exhibit JEM-2 CONFIDENTIAL, at page 6.

In the past two years, spot market prices in the southwest have been stable and quite low as a result of excess capacity regionally and stable and relatively low natural gas prices. Much of the generation on the margin in the southwest region is natural gas fired, often times highly efficient combined cycle units. In Section 2 of this testimony, Staff provides an analysis of market prices at the Mead Hub which clearly demonstrate that spot market prices are currently low and not very volatile.

In 2009–2010, spot market electricity prices were less expensive than the block power MEC purchased, and competitive with the variable cost of power purchased from AEPCO. Thus it is not reasonable to have an arbitrary limit on the amount of lower cost power MEC could procure from the spot market.

MEC did not reach its limit on spot market power in 2010, probably due to MEC's reduced loads during the economic downturn. The reduced loads mean that MEC's allocation of AEPCO resources is able to supply a larger fraction of MEC's energy requirements, resulting in less need for supplemental resources. If MEC's loads increase in the future, MEC will increase its reliance on supplemental resources. If natural gas prices remain stable and at current levels, the least expensive supplemental resource may well be the electricity spot market. It would thus behoove MEC to reconsider its arbitrary limit on the amount of spot market electricity it purchases to take advantage of potentially lower cost opportunities in the future and modify its policies of power supply planning and implementation accordingly.

RECOMMENDATIONS REGARDING STRUCTURE AND PROCEDURES

Q. What are Staff's recommendations regarding MEC's organization and power planning and procurement approaches and policies?

A. Staff recommends that the Commission:

a. Determine that MEC's policies of power supply planning and implementation as being implemented in 2010 are reasonable and appropriate, except for the limit on spot market power purchased.

b. Direct MEC to reconsider the limit on power purchased from the spot market to ensure that full advantage can be taken of lower costs, especially in the future when MEC needs to procure greater amounts of supplemental power and when spot market prices are relatively low and stable.

c. Determine that it is inconclusive whether MEC's policies of power supply planning and implementation being implemented prior to 2010 are reasonable and appropriate.

SECTION 2: PRUDENCE OF MEC'S POWER PURCHASES

Q. Staff concludes that MEC had reasonable and appropriate organizational structure and procurement procedures as they relate to power purchases. From that, can Staff conclude that MEC made power purchases at reasonable costs?

A. No. Effective organizational structure and procurement procedures would increase the likelihood that MEC would make appropriate purchases and decrease the likelihood of error and abuse. They do not guarantee appropriate purchases at reasonable cost.

Q. What should the Commission consider in determining whether MEC made power purchases at reasonable cost?

A. First, the Commission should consider whether the purchased power costs recorded by MEC are actually for purchased power. If not, the costs recovered through the base purchased power rate and the purchased power adjustor should be adjusted to include only the costs of purchased power.

Second, the Commission should consider whether the actual purchased power costs are reasonable and appropriately documented. This would be done by auditing the costs, ensuring that the costs were documented by appropriate invoices or receipts, and ensuring that the costs were market-based (e.g., determining whether the power purchases were with affiliated interests or subject to "sweetheart" deals).

Finally, in a competitive market, comparing prices paid to market prices is a way to measure whether the prices paid (and cost) were reasonable. The most appropriate way to compare MEC's purchases to market prices is on a marginal basis. That is, at any given time, Staff would analyze how MEC's marginal cost of supply compared to the market price at that time.

INELIGIBLE COSTS

Q. Regarding Staff's first point, did Staff conclude that all of the costs MEC recorded for recovery through the purchased power adjustor in 2010 were legitimate purchased power costs?

A. No. Upon careful review of the costs MEC proposed to recover as purchased power costs through the adjustor and base rates, MEC included significant ineligible costs among the purchased power cost in 2010 for staff and labor cost, consulting cost and legal cost. Please refer to the attached Exhibit JEM-6 CONFIDENTIAL for a breakdown of the costs that are ineligible for recovery through the adjustor. The purchased power bank balance for should be reduced by $594,737.45 to adjust for these 2010 ineligible costs.

MEC included $23,014.78 in its purchased power costs that was recorded as "Other (Fuel Bank Reporting)." This amount is for the services of a consultant to prepare the monthly fuel bank reports. It is not purchased power or the related transmission costs.

MEC included $571,722.67 in its purchased power costs that was recorded as "Other Expenses (Consultants, Employees and Legal)." Of that, $120,041.97 was for MEC's in-house staff labor and fringes. Please refer to the attached Exhibit JEM-7 CONFIDENTIAL for a breakdown of MEC's in-house labor costs. $335,233.34 was for legal services. An additional $32,037.96 was for lobbying services. The technical consultants provided services costing $83,745. Lobbying services, legal services, consulting and in-house payroll costs are not purchased power or the related transmission costs.

Q. Why are these costs ineligible to include in the purchased power costs?

A. They are not purchased power costs and should not be included in the purchased power adjustor clause. As a ratemaking principle, fuel and purchased power clauses are reserved for volatile price changes that are outside the control of the regulated utility. Costs such as consulting and lobbying and legal fees and in-house labor are within the utility's control and are recovered through the general rates.

The Commission observed these principles in July 2001 when deciding upon the restructuring of AEPCO to authorize MEC to become a Partial Requirements Member. In Decision No. 63868 in Docket No. E-01773A-00-0826, the Commission addressed the purchased power and fuel adjustor clause. See Exhibit JEM-8.

> 45. The fundamental rationale for a fuel adjustment clause is that fuel prices can ***change radically based on the overall energy market***...(Emphasis added)
>
> 46. Purchased power and fuel adjustor clauses for Arizona utilities may be created and set during a rate case wherein a base cost of ***fuel and purchased power*** is determined and included in base rates...(Emphasis added)

It is Staff's understanding that the Commission has not modified its straightforward approach of allowing only fuel and purchased power costs to be recovered through an adjustor. The Commission has not taken any action to allow labor, consulting, legal, lobbying and other costs potentially associated with fuel or purchased power to be included in the fuel and purchased power adjustors.

Q. Has MEC recovered in-house labor, consulting, lobbying and legal fees through its adjustor since becoming a partial requirements member in 2001?

A. No. MEC had incurred those kinds of costs since becoming a Partial Requirements Member in 2001, but had not recorded them as purchased power costs. In response to Data Request JMM-7.15, which is attached as Exhibit JEM-9, from 2001 through 2007, labor expenses were not booked as purchased power costs. In 2008, MEC began booking them as purchased power costs, but did not attempt to include them in the purchased power adjustor until 2010.

In response to Data Request JMM-7.16, which is attached as Exhibit JEM-10, from 2001 through 2008, consulting and legal expenses were not booked as purchased power costs. In 2009, MEC began booking some of them as purchased power costs, but did not attempt to include consulting and legal expenses in the purchased power adjustor until 2010.

Exhibit JEM-11 is the response to Data Request JM-4.14. This provides the breakout by the type of expense, the year and month it was incurred, and whether it was recovered from the purchased power adjustor. Again, it demonstrates that MEC was incurring these labor, consulting and legal costs, but did not attempt to recover them through the purchased power adjustor until 2010.

Q. Was there any doubt in MEC's interpretation of the commission's intent in the 2001 order regarding the costs that could be recovered through the purchased power adjustor?

A. No, it appears that there was no doubt for eight years after the order in Docket No. E-01773A-00-0826 that labor, consulting, lobbying and legal costs were ineligible for recovery through the purchased power adjustor. Otherwise, MEC would have attempted recovering them as early as 2001. Since the Commission did not revise its definition of eligible costs for MEC or any other utility, MEC's attempt to unilaterally change the definition should be rejected.

Q. Did MEC include any other ineligible costs in its purchased power adjustor during the audit period 2001 through 2010?

A. Not for the years 2007 through 2010. MEC provided the documentation supporting the purchased power costs included in the purchased power adjustor for 2007 through 2010. All of the costs included by MEC (other than the in-house, consulting, lobbying and legal costs in 2010 discussed above) were eligible purchased power costs.

Staff is unable to reach a conclusion regarding potential ineligible costs included in the purchased power adjustor for the years 2001 through 2006. MEC refused to provide any data regarding the purchased power adjustor or costs it comprised for the years 2001 through 2006 because MEC felt that information was irrelevant to this docket. Thus, Staff was unable to perform the detailed audit of the 2001 through 2006 purchased power costs.

APPROPRIATE DOCUMENTATION

Q. Regarding Staff's second point, did Staff conclude that the eligible purchased power costs are reasonable and appropriately documented in 2010?

A. Yes. All of the eligible purchased power costs going into the purchased power adjustor mechanism and into the energy bank are supported by invoices or documentation from MEC. The invoices are from entities that are either arms length parties at market rates (e.g., Western, PowerEx) or are subject to regulated rates (e.g., AEPCO, Southwest). MEC provided invoices and other documentation to support all of the eligible costs MEC included in its 2010 purchased power adjustor. As stated above, labor costs, consulting costs, lobbying costs and legal costs are not eligible for recovery through the purchased power adjustor and Staff has excluded them from the purchased power costs. As can be seen in Exhibit JEM-6 CONFIDENTIAL, page 2, some of the ineligible costs were not appropriately documented, but these are not part of the base purchased power or purchased power adjustor calculations. No adjustments to the eligible 2010 purchased power costs are required due to non-competitive arrangements or inadequate documentation.

Q. Did Staff also conclude that the actual purchased power costs are reasonable and appropriately documented in the rest of the audit period, 2001 through 2009?

A. No. For the period 2001 through 2006, MEC did not provide any information regarding purchased power costs, the quantity and cost of power purchased, from whom, or under what terms. Therefore, Staff is not able to conclude that the purchased power costs recovered by MEC through the purchased power adjustor in 2001 through 2006 are reasonable. Whatever costs MEC included are clearly not documented.

MEC provided detailed purchased power information and documentation for the years 2007 through 2010. For 2007, 2009 and 2010, the information and documentation was in order and Staff was able to conclude that the purchased power costs MEC recovered through the purchased power adjustor were reasonable and are supported by invoices. In 2007 and 2009, like 2010, the invoices are from entities that are either arms length parties at market rates or are subject to regulated rates. MEC provided invoices and other documentation to support all of the eligible costs MEC included in its 2007 and 2009 purchased power adjustors.

MEC did not provide invoices to support all of its purchased power costs for 2008 for the firm transmission services. This information was not supplied in response to data request JM-3.48, which requested all supporting documents that were used to establish the purchase price. It was not provided in response to data request JMM-7.8, which requested all invoices missing from the information provided in response to JM-3.48. It was not provided in response to data request JEM-9.14, which identified the specific months and expenses for which invoices were missing. Exhibit JEM-12 shows the data requests identified above.

Q. How much of the 2008 purchased power cost included by MEC in its purchased power adjustor was not supported by invoices or other reasonable documentation

A. Although MEC provided many invoices to support its reported purchased power cost in 2008, MEC did not provide the invoices to support $163,221.69 for the firm transmission services provided by WAPA for the months of June through November. Please refer to Exhibit JEM-13 CONFIDENTIAL. The purchased power and fuel adjustor bank balance report should be adjusted with a $163,221.69 credit to ratepayers to refund the unsupported expense recorded in 2008.

COMPARISON OF MEC'S COSTS TO MARKET PRICES

Q. Regarding Staff's third point, how did MEC's purchased power costs compare to market prices?

A. From 2001 through mid-2008, MEC's average purchased power cost compared favorably with regional market prices. Since mid 2008, MEC's average purchased power cost remained quite stable, while the market prices dropped substantially. MEC's average power costs since mid-2008 are significantly higher than regional market prices.

Q. What analysis did Staff perform to conclude that MEC's average costs were comparable to market prices through mid-2008, but have since been above market prices?

A. Staff compiled detailed purchased power cost information provided by MEC in response to JM-7.8 for 2007-2010 (See Exhibit JEM-12, page 2) and unverified purchased power cost information from Staff for 2001 through 2006. The Staff information was a compilation of monthly purchased power adjustor reports submitted to the Commission by MEC, but did not necessarily include the revisions that often accompany these filings or the supporting information to verify the reported numbers. Staff then removed the transmission costs from each of these monthly purchased power costs to determine an average monthly electricity commodity cost.

Staff then took the Mead hub monthly on-peak and off-peak electricity index prices provided by MEC in response to Staff data request JM-3.64 (attached as Exhibit JEM-14 CONFIDENTIAL). Because MEC purchases power from AEPCO and block power suppliers based on an average price that is in effect for the entire month or more, MEC does not face on-peak and off-peak price signals. However, one would expect that MEC's average price should in theory lie somewhere between the Mead off-peak and the Mead on-peak prices if MEC's average costs are competitive with market prices.

Figure Mendl Direct 1 CONFIDENTIAL summarizes the result of that analysis. Also, see Exhibit JEM-15 CONFIDENTIAL, pages 1 and 2. The analysis shows MEC's average monthly purchased power cost, excluding transmission, generally tracking Mead on-peak/off-peak price trends, although not always falling directly within the off-peak to on-peak price range (the shaded area in Figure Mendl Direct 1 CONFIDENTIAL and Exhibit JEM-15 CONFIDENTIAL, pages 1 and 2).

Figure Mendl Direct 1 CONFIDENTIAL

[redacted]

AEPCO PURCHASES

Q. Is Staff concerned that MEC's average cost of purchased power does not exactly track the market prices?

A. It does not surprise Staff that MEC's average costs do not exactly track market prices – MEC's average costs lag AEPCO's production costs by up to six months due to the biennial operation of AEPCO's fuel and purchased power adjustor. AEPCO's production costs would be more likely to track the market than AEPCO's approved rates with its fuel and purchased power adjustor, but MEC's price is the approved rate with the lags. In addition, AEPCO's prices (which are a significant portion of MEC's costs) are based on average cost of service, while market prices are based on marginal cost of service.

Q. Does the fact that MEC's average cost of purchased power is significantly above the market price since mid-2008 mean that MEC purchased power imprudently?

A. No, MEC owns and pays for its member share of AEPCO capacity through fixed charges and demand charges. In effect, those are sunk costs that MEC is obligated to pay irrespective of the amount of energy that Western dispatches from those resources. MEC is under contract to receive the AEPCO resources through 2035, or until the resources are retired. In light of those sunk costs, the appropriate cost minimization strategy is to minimize the variable cost.

MEC's planning and procurement strategies rightly call for the minimization of variable costs. These strategies include monitoring the markets to determine whether there are resources available that cost less than the variable cost of MEC's existing resources. A determination is also made as to whether market prices are above the variable cost of MEC's existing resources, which represents an opportunity for MEC to sell any excess power it may have available from its existing resources. In other words, MEC has procedures for optimizing MEC's portfolio of resources by minimizing variable costs and maximizing the sales of power in excess of MEC's needs.

Q. One would expect that MEC's variable costs would be at or below the market power price if MEC was minimizing its costs. How does the MEC's variable cost of purchased power compare to the market price?

A. Figure Mendl Direct 2 CONFIDENTIAL (also Exhibit JEM-15 CONFIDENTIAL, page 3) shows that AEPCO's variable price component, which is the dominant driver of MEC's variable cost, was less than market prices for the period January 2007 through mid-2008, and has been approximately at market prices from mid 2008 through December 2010. This suggests that MEC's purchased power from AEPCO is near market prices, even after the natural gas prices dropped in mid-2008. Prior to that, higher natural gas prices kept electric market prices, which are largely based on natural gas fired generation, higher than AEPCO's variable price. Based on this, Staff concludes that MEC's purchased power strategy relying on AEPCO for the majority of its supply has been prudent and reasonable, at least for the 2007-2010 period for which Staff had detailed information.

Figure Mendl Direct 2 CONFIDENTIAL

[redacted]

COMPARISON OF MEC'S BLOCK POWER COSTS TO MARKET PRICES

Q. MEC's power planning and procurement strategy also relies on supplementing AEPCO power with block purchases in the peak summer months. How did these block purchases compare in price to market prices and AEPCO's prices?

A. The average cost per kWh of MEC's block power purchases was generally above the Mead market prices and often above MEC's average cost per kWh during the period January 2007 through December 2010. Of the 21 block purchase contract months during this period, 13 were above MEC's average cost. Only four were at or below the corresponding on-peak price at Mead. Exhibit JEM-15 CONFIDENTIAL, page 4, is a graph depicting the block purchases in comparison to MEC's average cost of purchased power and Mead market prices.

Q. Were MEC's block power purchases made above market prices imprudent?

A. Probably not. Imprudence is a possible explanation, but there are other plausible explanations that cannot be ruled out. First, Mead market prices, especially during periods of adequate or excess capacity, probably reflect little capacity value, i.e., under those circumstances Mead prices mostly recover energy costs with a small margin for the seller.

In contrast, when MEC is seeking block power, it is seeking capacity with a relatively low load factor. The products are different and may be priced differently.

Second, block power is an on-peak resource. One would expect that its cost per kWh would be higher than MEC's average costs, since the average cost includes the lower prices associated with off-peak hours.

Third, the nature of the block power purchase contract can also affect its average cost per kWh. If the contract requires MEC to purchase capacity, but not energy, the capacity cost – a sunk cost - may be spread over fewer kWhs, with the effect of inflating the average cost per kWh. If the contract requires MEC to purchase capacity and a fixed block of associated energy, then this on-peak service is higher than average price service.

[redacted]

[redacted]

[redacted] Staff concludes that MEC's actions regarding power purchases are prudent and reasonable. Although the block purchased power prices are somewhat higher than the aggregate market price, the differences may be explained by the differences in products (capacity versus spot market energy).

Q. How much block power did MEC utilize in its resource portfolios?

A. MEC's block power supplies comprised [redacted] of MEC's total purchased power resources in 2010. It was [redacted] in 2007, [redacted] in 2008 and [redacted] in 2009. MEC's response to Staff data request JMM-7.21, which is attached as Exhibit JEM-16 CONFIDENTIAL, provides additional information on MEC's purchased power resources for 2007 through 2010.

In contrast, AEPCO comprised [redacted] of MEC's purchased power in 2007 and 2008, [redacted] in 2009 and [redacted] in 2010. Staff's conclusion is that block power purchases do not substantially affect MEC's overall purchased power cost.

Q. How does the response to JMM-7.21 compare to Staff's analysis as presented in exhibit JEM-15 confidential?

A. MEC's response, attached as Exhibit JEM-16 CONFIDENTIAL is consistent with Staff's analysis. MEC provided data showing the power purchased from AEPCO being less expensive, on average, than block power purchases or power purchased from the market (AES purchases) in 2007-2008. In 2009-2010, power from AEPCO was still less expensive than block power purchases, but more expensive than market purchases.

PRUDENCE PRIOR TO 2007

Q. What has Staff concluded about the prudence of MEC's purchased power costs between July 25, 2001 and December 31, 2006?

A. Nothing. As described earlier in Staff's testimony, MEC objected to providing information prior to 2007. See MEC's narrative (Exhibit JEM-2 CONFIDENTIAL, page 1). Therefore Staff can make no determination regarding the prudence of MEC's power purchases prior to 2007. With MEC being unwilling or unable to provide the information needed to assess the prudence of MEC's power purchases prior to 2007, the options are limited.

Q. What options does the Commission have available to address the prudence of MEC's purchased power costs between July 25, 2001 and December 31, 2006?

A. The Commission could direct MEC to file the needed information, but it is likely that the requisite information is no longer available. Even if MEC provided its purchased power information, it would also have to reconstruct the context of the market and other parameters in that time period. Doing this option would be at best time consuming and burdensome, if even possible.

The Commission could give a "free pass" to MEC. That is, the Commission could accept as prudent those costs that MEC asserted to be prudent during the July 25, 2001 through December 31, 2006 time frame. The drawback to this is that it sends a signal that a utility can avoid scrutiny by failing to maintain records and file requested information.

The Commission could impose a 1% prudence adjustment and accept 99% of the purchased power costs for the July 25, 2001 through December 31, 2006 time frame. This would be because MEC failed to maintain and provide the information to support the prudence of its purchased power

The Commission could require MEC to file a rate case with purchased power prudence review no later than April 1, 2016, with a test year ending December 31, 2015, so that no more than five years elapses between this rate case and the next rate case to ensure the purchased power cost data and supporting information remain fresh. In addition, require MEC to maintain all files and records pertinent to their purchased power planning and procurement, and to document the prudence of the purchased power expenditures. Should Staff determine that insufficient information is provided in its next rate case filing; Staff could recommend that any undocumented and/or unverified costs be returned to the ratepayers including interest or that the purchased power adjustor be eliminated.

Q. How much would the 1% prudence adjustment between July 25, 2001 and December 31, 2006 affect MEC's purchased power bank balance?

A. The unverified purchased power costs reported to the Commission Staff and the resultant prudence adjustment are as follows:

Period	Purchased Power Cost	1% Prudence Adjustment
Aug-Dec, 2001	12,435,419	124,000
2002	31,326,701	313,000
2003	32,195,488	322,000
2004	35,724,426	357,000
2005	35,820,510	358,000
2006	47,178,730	472,000
TOTAL	194,681,274	1,946,000

The 1% prudence adjustment would reduce MEC's purchased power bank balance by $1.946 million, i.e., ratepayers would receive a credit of that amount

THIRD PARTY SALES

Q. Do MEC's sales to third parties generate a profit for MEC?

A. Not always. There are times when MEC sells excess capacity to third parties at a loss. At other times, third party sales result in profits. In addition to losses on third party sales, MEC may also at times incur a lost opportunity, that is, to fail to make a sale that would have resulted in a profit.

Both losses on sales and lost opportunities to sell at a positive margin are detrimental to MEC's ratepayers. Yet under the approaches in place through 2010, either of these outcomes could occur (as well as the positive outcome of making a sale for a positive margin).

Q. PLEASE EXPLAIN.

A. The problem is due to the AEPCO pricing structure in effect through 2010. Under this structure, AEPCO would charge MEC a fixed fee for its allocated share of capacity, a demand charge, an energy charge for a base rate and a fuel and purchased power adjustor. The Commission set all of these rates, and the adjustor could change twice yearly.

MEC's cost of purchased power at any point in time is based on its demands and those four factors in AEPCO's rate (fixed fee for allocated share of capacity, a demand charge, base rate energy charge and fuel and purchased power cost adjustor). AEPCO's actual cost of producing power to serve MEC at that time may be higher or lower than is covered by the rates it charges MEC. In other words, AEPCO's marginal production cost may not be the same as its energy base plus adjustor rates.

MEC and Western are not aware of AEPCO's marginal production cost when dispatch decisions between alternative suppliers are being made. Whether MEC is interested in selling to a third party or simply trying to decide from whom it should purchase its own energy needs, MEC only knows the rate that AEPCO is charging MEC. MEC knows the regulated rate plus the adjustor in effect at the time the purchase is being made to supply MEC's native load or to dispatch more power from its existing resources to sell to third parties. Normally, knowing your cost at the time you are evaluating your options would be adequate.

However, AEPCO's adjustor ensures that AEPCO ultimately recovers its actual prudent costs. If AEPCO's marginal production costs are above what MEC is paying AEPCO for power, AEPCO's adjustor will increase in a future period, and MEC will pay the difference at some future time. Thus, when MEC (or Western on MEC's behalf) is making decisions whether to purchase more power from AEPCO, it does not know the ultimate actual cost of that power for which MEC will be liable when AEPCO's adjustor is modified to reflect actual costs.

In this way, MEC can engage in what it anticipates will be a third party sale for profit and actually incur a loss. Or it can forego an opportunity to sell power at what it anticipates will be a loss and actually miss an opportunity to sell at a profit.

Q. In Staff's analysis, has Staff found instances where MEC sold power to third parties at an apparent loss?

A. Yes. Staff compared the revenues received from third party sales to the AEPCO rates in effect for each month in the 2007-2009 time period for which data was available. At least one sale for a loss incurred in one month in 2007, two months in 2008, 10 months in 2009, and 10 months in 2010. The total losses from these sales appear to be about $39,000.

Q. Did Staff analyze instances where MEC missed an opportunity to sell power to third parties at a profit?

A. No. Staff had no information that would have permitted Staff to know what opportunities MEC had, and thus was not able to quantify the lost opportunities.

Q. The same types of problems would appear to apply to MEC's decisions whether to purchase energy to meet MEC's native load from AEPCO or another supplier. Did Staff identify any such instances that adversely affected MEC's ratepayers by purchasing power from AEPCO rather than another supplier or visa versa?

A. Staff did not perform such an analysis. It would require having hourly marginal production cost for AEPCO and each alternative supplier.

Q. What can be done to avoid sales for a loss and lost opportunities to sell for a profit?

A. The most direct solution is to dispatch resources on the basis of each source's marginal production cost rather than the rate charged. That would require MEC and Western knowing AEPCO's marginal production costs on an hourly basis. MEC could estimate the cost trends that AEPCO is facing by reviewing AEPCO's monthly fuel and purchased power reports. While it would not provide real time data, it may provide insight into the likely future costs based on historic costs. MEC chose this method prior to and during 2010, as indicated in its response to JMM-7.6, which is attached as Exhibit JEM-17. This method is not particularly useful when AEPCO's fuel and purchased power costs are volatile in that large or unpredictable changes will not be captured by the simple trend analysis.

The Commission mitigated the problem somewhat with modifications to AEPCO's pricing approach. Through 2010, AEPCO charged a Schedule A rate that was based on the costs for a mix of coal and natural gas fired resources to meet MEC's load profile. The volatility of natural gas prices led to an unpredictability in AEPCO's adjustor and hence in the cost responsibility MEC would bear. Starting January 1, 2011, AEPCO began implementing a new rate which is based on base and other (natural gas fired) resources. This results in more predictable rates for base power which is the primary source of power for MEC native load and for sales of excess capacity to third parties. It is anticipated that this will result in better cost information and improved decision-making. However, this is a new approach with which there is little actual experience at this time. The Commission should re-evaluate the efficacy of this approach, which does not eliminate the root problem but reduces the fuel cost uncertainty by better lumping together like cost resources, after more data regarding MEC's experience with it becomes available.

Q. Would the same solutions apply to decisions whether to purchase power to serve MEC's native loads from AEPCO or another supplier?

A. Yes.

RECOMMENDATIONS REGARDING PRUDENCE OF MEC'S POWER PURCHASES

Q. What are Staff's recommendations regarding the prudence of MEC's power purchases?

A. Staff recommends that the Commission:

a. Reaffirm that for purposes of the purchased power adjustor, purchased power includes only the actual costs of purchased power and associated transmission and reject MEC's unilateral attempt to include ineligible costs.

b. Remove from the 2010 base revenues those costs ineligible for recovery through the purchased power adjustor that MEC has included as purchased power costs in 2010, namely in-house labor costs, consulting costs and legal costs associated with planning and procurement of purchased power.

c. Reduce MEC's purchased power bank balance by $594,737.45 to adjust for the inclusion of these ineligible costs.

d. Determine that the actual eligible purchased power costs were adequately documented in 2007, 2009 and 2010.

e. Disallow MEC's undocumented claim of purchased power expenses of $163,221.69 in 2008, and reduce MEC's purchased power bank balance by that amount.

f. Determine that MEC's actual purchased power costs, adjusted to remove the ineligible and undocumented costs, are prudent and reasonable for 2007-2009.

g. Determine that MEC's objection to providing information prior to 2007 made it impossible to assess whether purchased power costs between July 25, 2001 and December 31, 2006 were prudent and reasonable.

h. Impose a prudence adjustment of $1.946 million (equal to 1% of MEC's purchased power costs between July 25, 2001 and December 31, 2006) and reduce MEC's purchased power bank balance by that amount.

i. Require MEC to file a rate case with purchased power prudence review no later than April 1, 2016, with a test year ending December 31, 2015, so that no more than five years elapses between this rate case and the next rate case to ensure the purchased power cost data and supporting information remains fresh. In addition, require MEC to maintain all files and records pertinent to their purchased power planning and procurement, and to document the prudence of the purchased power expenditures. Should Staff determine that insufficient information is provided; Staff may recommend that any undocumented and/or unverified costs be denied including interest or that the purchased power adjustor be eliminated.

j. Acknowledge that MEC's selection and management of Western to provide critical services are prudent and reasonable.

k. Require MEC to request information regarding AEPCO's marginal operating costs so that regional power dispatch decisions could be made based on actual real time costs rather than average costs over a six-month period.

SECTION 3: IMPROVEMENTS TO MEC'S ADJUSTOR MECHANISM

Q. Does Staff have any recommended improvements to MEC's adjustor mechanism?

A. Yes. Staff has three suggestions for the Commission to consider. First, as Staff indicated previously, MEC should be required to submit a rate case no later than April 1, 2016, with a test year ending December 31, 2015, so that no more than five years elapse between this rate case and the next rate case. Limiting the amount of purchased power cost not yet subject to prudence review to a maximum of five years of costs would keep the information needed for prudence review fresh and current. It would also avoid surprises of having potential disallowances, especially large disallowances that could accumulate over many years.

Second, Staff noted that MEC does not credit the purchased power costs with the revenues from third party sales, or, more generally, any sales that are not subject to the adjustor rate. MEC's calculation of the adjustor and the bank balance subtracts the cost of power purchased for sales to third parties from the total cost of purchased power. While that yields a net cost of purchased power for retail sales subject to the adjustor mechanism, it does not address what happens to the net revenues from the sales made to third parties and special contracts that are not subject to the purchased power adjustor mechanism. Staff recommends that the Commission require the revenues to offset the purchased power costs.

Q. Please explain in more detail the treatment of margins on third party power sales.

A. When a utility purchases fuel and power to meet its loads, it would argue that those costs are to be recovered from the ratepayers through its energy rates and fuel adjustment clause. When the purchased fuel and power is not fully utilized by its customers, the utility can reduce customer costs by selling the excess fuel and purchased power. The question is what happens to the revenues from the sale of excess fuel and power.

In MEC's approach, it calculates the amount of third party energy sold, calculates its cost of that energy, and reduces the cost of purchased power recovered from ratepayers by that amount. The revenues generated by the sale do not enter the ratepayer purchased power adjustor calculation. Rather these revenues (net of the calculated cost of the power) end up in the member's patronage capital credit account where it is available to fund construction or operations. Refer to MEC's response to Staff data request JEM-8.8, attached as Exhibit JEM-18. Part of MEC's purchased power costs are handled through the purchased power adjustor mechanism and part through other accounts. MEC's approach should indirectly flow margins on third party sales back to MEC's ratepayers. How quickly and to which ratepayers the margins are returned is unclear as it would depend on the cash flow and cash needs at the time.

Another approach is to subtract the revenues from the third party sales from the total cost of purchased power. This approach reduces the purchased power cost by the cost of the power for third party sales (same as the MEC approach) ***and*** the margin on those sales. Thus all of the purchased power costs and margins are handled within the purchased power adjustor mechanism. Margins on third party sales flow immediately and directly to the ratepayers.

Q. Would the same considerations apply to special contract sales, such as LC&I Substation customers that are not subject to the purchased power adjustor?

A. Yes, it is Staff's understanding MEC's special contract with an LC&I substation customer has terminated and that there are currently no special contract sales or plans for new special contracts.

Q. How large are the margins that MEC collected on third party sales?

A. The margins vary from year to year. According to MEC's initial filing for a 2009 test year, Schedule F-4.1 (attached as Exhibit JEM-18, page 2), the *projected* margin for third party sales is $309,874.82. Based on MEC's supplemental filing for a 2010 test year, Schedule F-4.1 (attached as Exhibit JEM-18, page 3), the *projected* margin for third party sales is $475,686.89. MEC is proposing revenue requirements and rates based on the 2009 test year. Staff is basing revenue requirements and rates on the 2010 test year. Note that both the 2009 and 2010 margins are based on MEC's expectation that third party sales will increase to 76,313,520 kWh from their actual 2009 and 2010 volumes.

Staff estimated the margins based on actual AES non-jurisdictional sales volumes, costs and revenues in 2007-2010. The margins are stated in Exhibit JEM-19 CONFIDENTIAL. The fact that these actual margins can vary so much based on actual sales volumes, MEC's purchased power costs, and market prices add impetus to including the margins in the purchased power adjustor mechanism.

Q. How can the recommendation that the Commission require the revenues from sales to entities not subject to the purchased power adjustor to offset the purchased power costs be implemented?

A. The method can be implemented simply by subtracting the total revenue from sales to entities not subject to the purchased power adjustor (rather than only the cost of power sold to those entities – the current practice) from the total purchased power cost. Everything else is the same.

Q. In its response to Staff data request JEM-8.8 (attached as exhibit JEM-18), MEC indicates that it included $309,874 in margins from third party sales in its 2009 test year calculations and reduced the requested rate increase by that amount. If the Commission adopts Staff's recommendation, would Staff agree with MEC's adjustment to increase the requested rate increase by that amount?

A. In principle, yes. If the Commission adopts Staff's recommendation, the margins would no longer contribute to the member's patronage capital credit account. Thus, MEC's requested rate increase would need to be increased by the amount of MEC's estimated margins from third party sales, which had previously offset general revenue requirements and under Staff's proposal would instead offset purchased power costs. According to MEC's calculations, the Commission should remove $309,874 based on the 2009 test year. It should remove $475,687 based on the 2010 test year recommended by Staff. If the Commission adopts Staff's recommendation, the 2010 test year general revenue requirement would be increased by $475,687 to reflect MEC's anticipated reduction in contributions from the margins to the patronage capital credit account. But the purchased power base cost would be decreased by $475,687, bringing MEC to a revenue neutral position with respect to its calculated test year margins.

Since Staff's proposal would flow the margins through the purchased power adjustor, the net power cost would be self correcting for variations in: i) MEC's actual price of purchased power for resale; ii) actual price at which the power was sold; and iii) the volume of sales. If the $475,687 reduction in base purchased power cost understates the margins (such as 2008) the additional credit will flow to MEC's ratepayers. If the $475,687 reduction in base purchased power cost overstates the margins (such as 2009–see Exhibit JEM-19 CONFIDENTIAL), the additional cost will be assessed to MEC's ratepayers.

Under Staff's proposal it is not necessary to predict with accuracy the third party sales margins to include in the base purchased power cost. The adjustor mechanism will self correct for any deviations from the expected. However, since the intent of the purchased power adjustor mechanism is to estimate the base purchased power cost to zero-out the adjustor rate, it would be more appropriate to reduce the base purchased power cost by the expected margins to at least begin with a zero adjustor rate.

In contrast, MEC's method of applying third party sales margins to member's patronage capital credit account means that MEC's earnings could fluctuate greatly depending on the margins on the third party sales market.

Q. Are MEC's estimates of the margins on third party sales, $309,874.82 for test year 2009 or $475,686.89 for test year 2010 reasonable?

A. They are reasonable amounts by which to reduce the base purchased power cost under Staff's proposal because variations from the forecasted margins are self correcting. The issue is more significant for MEC's proposal to set a fixed level of expected margins, which then directly affect its earnings.

The projected margins per kWh calculated by MEC were $0.004061/kWh based on 2009 and $0.006233/kWh based on 2010. (See Exhibit JEM-18) These projected margins are similar to the actual margins that Staff estimated in 2009 and 2010, so both appear reflective of the lower electricity market prices after mid-2008. (See Exhibit JEM-19 CONFIDENTIAL)

However, Staff did not attempt to verify the accuracy of MEC's third party sales margin forecasts to the level that would be required when it affects MEC's overall returns, as it does in MEC's approach. Is it reasonable to expect future third party sales volumes that are 60% more than 2010 actual levels and more than four times the 2009 levels? Is it reasonable to expect that changing AEPCO's pricing will result in increased third party sales? Will it result in less uncertainty in dispatching resources with the result that transactions will occur at lower thresholds of minimum benefits, i.e., that MEC can get a reasonable probability of a positive margin even with smaller expected margins on individual transactions? Will the result be more sales at lower margins? These questions cannot be answered until there is an adequate base of experience with the new dispatch opportunities under AEPCO's new pricing strategy which went into effect in January 2011.

RECOMMENDATIONS REGARDING IMPROVEMENTS TO MEC'S ADJUSTOR MECHANISM

Q. Please summarize Staff's recommendations regarding improvements to the purchased power adjustor mechanism.

A. Staff recommends that the Commission:

a) Revise MEC's purchased power adjustor mechanism to use margins on third party sales to offset purchased power costs.

b) Subtract total revenues from third party sales from total cost of purchased power, including power for third party sales, to determine new purchased power costs.

c) Require MEC to file its next rate case no later than April 1, 2016, using a test year of 2015. MEC may file sooner if necessary.

SECTION 4: MEC'S BASE COST OF POWER

BASE POWER COSTS

Q. What period did Staff use to establish the base cost of power?

A. Staff used calendar year 2010 to determine the base cost of purchased power: 2010 is the most current year for which data were available.

Q. Will 2010 be representative of the base power costs in future years?

A. It is the best information currently available, but it may not be representative of purchased power in 2011 and beyond. The reason is that the Commission approved a new rate for AEPCO which went into effect on January 1, 2011. The new rate modifies the pricing structure under which MEC purchases power from AEPCO in that after 2010, base resources are plants with similar cost characteristics. Other resources are likewise grouped with similar cost characteristics. Under the rates in place through 2010, base resources included a slice of resources with differing cost characteristics, which made it more difficult to predict operating costs for which MEC would ultimately be liable through AEPCO's fuel clause. To avoid entering transactions that would result in economic loss to MEC, MEC adopted a conservative approach to power sales to third parties, and instructed Western to dispatch resources accordingly.

As a result of AEPCO's new rate structure to reduce cost uncertainty, MEC may be able to dispatch its resources differently, thus affecting overall purchased power costs. At this point, it is unclear how large the effect of changed dispatch will be.

ACTUAL POWER COST IN 2010

Q. What was MEC's actual cost of power in 2010?

A. MEC'S Supplemental filing (Schedule F-5.0, page 2) showed an unadjusted jurisdictional purchased power cost of $52,128,007.66. This cost does not match the unadjusted jurisdictional purchased power costs reported in the supplemental response to Staff data request JM-3.48, where $52,270,355.91 was used to calculate the purchased power bank balances reported to the Commission on form FA-1 in 2010. For the purposes of developing the base purchased power cost, Staff elected to use the Supplemental filing to the application because the Supplemental filing would presumably be MEC's internally consistent information set, whereas the response to JM-3.48 was provided by Guernsey for a different purpose. The response to JM-3.48 was initially delayed because Guernsey discovered that its spreadsheets needed to be updated. Staff anticipates that MEC will reconcile the differences between fuel costs it provided for 2010 and will verify the proper calculation of the bank balance in its rebuttal testimony.

Q. What was MEC's actual sales volume of power subject to the purchased power adjustor in 2010?

A. MEC'S Supplemental filing (Schedule F-5.0, page 1) showed the unadjusted jurisdictional purchased power sales subject to the purchased power adjustor to be 618,974,832 kWh in 2010. This cost does not match the unadjusted jurisdictional sales subject to the purchased power adjustor reported in the supplemental response to Staff data request JM-3.48, where 619,478,531 kWh was used to calculate the purchased power bank balances reported to the Commission on form FA-1 in 2010. For the purposes of developing the base purchased power cost, Staff elected to use the Supplemental filing to the application for the reasons described above. Staff anticipates that MEC will reconcile the differences between sales volumes it provided for 2010 and will verify the proper calculation of the bank balance in its rebuttal testimony.

Q. What was the unadjusted purchased power cost per kwh for 2010?

A. The unadjusted purchased power cost per kWh for 2010 was $0.084217/kWh. The derivation of this value is shown on Exhibit JEM-20 CONFIDENTIAL, page 1. This would be the base purchased power cost to be set in this rate case if the 2010 actual experience was representative of future conditions.

MEC ADJUSTMENTS

Q. What adjustments to the actual 2010 experience did MEC propose to develop the 2010 test year base purchased power costs?

A. The LC&I Substation customers special rate has terminated, meaning that both the costs of power and the volume of power subject to the purchased power adjustor would increase. MEC assumed that the volume of purchases by LC&I Substation customers would remain the same. The net result of this adjustment was to add $2,305,383.70 to the purchased power costs and 35,668,800 kWh to the sales volume subject to the purchased power adjustor.

MEC also recalculated the cost of power purchased from AEPCO under the new rates effective January 1, 2011. This adjustment added $4,146,305.34 to the purchased power costs and 0 kWh to the sales volume subject to the purchased power adjustor.

MEC's third adjustment was to make lighting sales subject to the purchased power adjustor. This adjustment increased the sales volume in 2010 subject to the purchased power adjustor by 1,100,103 kWh.

Q. Does Staff agree with these adjustments to the actual 2010 test year?

A. Yes. The net effect of these adjustments is a base purchased power cost per kWh of $0.089333. The derivation is shown in Exhibit JEM-20 CONFIDENTIAL, page 2.

Staff's calculation to this point is consistent with MEC's. MEC calculated the same power cost per kWh sold in Supplemental Schedule N-2.0, which is attached as Exhibit JEM-21, page 1.

Q. Why is MEC proposing a base purchased power cost per kwh of $0.091183 if its own calculation for 2010 shows it to be $0.089333 per kwh?

A. MEC calculated the $0.091183 per kWh value for the base purchased power cost based on its initial 2009 test year. MEC also decided to adhere to its original proposal based on 2009 even after submitting the 2010 supplemental information because it believed that 2009 remained representative of MEC's current operations. (Searcy Supplemental Direct Testimony, page 6)

Exhibit JEM-21, page 1 shows that using MEC's proposed value for the base purchased power cost developed for a 2009 test year with 2010 test year data will result in a base purchased power that over-collects purchased power costs. As a result, MEC intentionally starts off with a negative purchased power adjustor cost to offset the over-collection rather than beginning with a zero adjustor.

Q. Did MEC make any adjustments to the 2010 test year for third party sales?

A. As previously discussed, MEC increased its third party sales forecast to 76,313,520 kWh. MEC also increased its purchased power cost to $3,222,979.80 to provide a supply for the increased sales volumes. Because MEC treats third party sales as separate from the purchased power adjustor, these changes did not cause any change in the base purchased power costs per kWh. The derivation is shown in Exhibit JEM-20 CONFIDENTIAL, page 3.

Q. How did MEC's revision of the third party sales projections affect the test year revenue requirement, since it did not affect the base purchased power cost and adjustor?

A. As stated earlier, MEC's revision of the third party sales forecast results in a projected margin on the sales of $475,686.89 which is credited to ratepayers outside the adjustor mechanism.

STAFF ADJUSTMENTS

Q. What is the effect on the base purchased power cost of Staff's proposal, discussed in section 2, to remove ineligible costs?

A. The effect of removing $571,722.67 for in-house labor, consulting, lobbying and legal fees and $23,014.78 for consulting on fuel bank reporting is to lower the base purchased power cost per kWh to $0.088426 per kWh. The derivation is shown in Exhibit JEM-20 CONFIDENTIAL, page 4.

The costs that Staff has removed as ineligible for purchased power are not necessarily imprudent. The prudent portions of those costs should be recorded in their proper accounts for recovery through general rates, but not in the purchased power accounts. The

$571,722.67 for in-house labor, consulting, lobbying and legal fees includes [redacted] related to lobbying.

Q. What is the effect on the base purchased power cost of Staff's proposal, discussed in section 3, to include the margins on third party sales in the purchased power base and adjustor calculations?

A. Staff has applied MEC's calculated profit on the third party sales of $475,686.89 as an offset to purchased power costs, thus flowing all third party power sales margins back to the ratepayers quickly and efficiently.

The profits on third party sales reduce the purchased power costs and thus the base cost of purchased power per kWh. The affect on the 2010 test year is to reduce the base purchased power cost per kWh to $0.087701 per kWh. The derivation is shown in Exhibit JEM-20 CONFIDENTIAL, page 5. The removal of the third party margins as a credit to the general rates requires that the general rates be raised accordingly.

Q. What purchased power cost does Staff recommend for setting rates for MEC?

A. All of Staff's recommended adjustments are summarized in Exhibit JEM-22 CONFIDENTIAL.

For the purposes of setting the base purchased power cost, Staff recommends that the Commission use $57,509,272 as the purchased power cost coupled with 655,743,735 kWh of jurisdictional sales.

For the purposes of determining MEC's overall operating costs and operating expenses, the Commission should use $61,207,939 as the purchased power cost (to supply both MEC native and third party sales for resale) coupled with 732,057,255 kWh of total sales.

PURCHASED POWER COST BANK ADJUSTMENTS

Q. Please summarize the adjustments that you recommended to the purchased power cost bank balance.

A. Staff recommends the following adjustment.

- In Section 2, Staff recommends disallowing $594,737.45 in ineligible costs in 2010, the first year that MEC included in-house labor, consulting, lobbying and legal fees in the purchased power costs. Because they were recovered improperly through the purchased power adjustor, it is necessary to adjust the bank balance by that amount to return the money to the ratepayers.

- In Section 2, Staff also recommends disallowing $163,221.69 for firm transmission service from WAPA in undocumented purchased power costs from 2008.

- Finally in Section 2 Staff also recommends disallowing $1,946,000 as a prudence adjustment for undocumented purchased power costs from August 2001 through December 2006.

Q. Would it not be double-counting the adjustment for in-house labor, consulting, lobbying and legal fees by including it as an adjustment to the purchased power cost bank balance as well as to base 2010 base purchased power cost per kwh?

A. No. The disallowance in 2010 for the ineligible expenses refunds money that was already charged to and accounted for in the bank balances. Making the adjustment to the bank balance reverses the existing error. Adjusting the base purchased power cost for the 2010 test year removes the ineligible expenses and ensures that they will not be collected through the purchased power cost adjustor mechanism in the future.

Q. How would the Commission make the adjustments to the purchased power cost bank balance?

A. I recommend that the Commission make a one time adjustment of $2.704 million to the bank balance to reflect the recommended disallowances. The adjustment should be made to bank balance as of December 31, 2010 as soon as practicable after the order is issued.

A further adjustment would have to be made to remove ineligible costs (in-house labor, consulting, lobbying and legal costs) MEC collected during 2011 and 2012 up to the date of the order.

RECOMMENDATIONS REGARDING PURCHASED POWER COST ADJUSTMENTS

Q. Please summarize your recommendations regarding the base purchased power costs and the adjustments to the purchased power cost bank balance.

A. The Commission should:

1) Adopt a base purchased power cost per kWh of $0.087701/kWh.

2) Adjust the bank balance to credit the ratepayers with $2.704 million, consisting of $594,737 of ineligible costs in 2010, $163,222 of undocumented costs in 2008, and $1.946 million for undocumented purchased power costs in 2001-2006.

3) Direct MEC to adjust the bank balance for any ineligible costs that may have been recovered through the purchased power cost adjustor after December 31, 2010.

SUMMARY OF STAFF'S RECOMMENDATIONS

1. Determine that MEC's policies of power supply planning and implementation as being implemented in 2010 are reasonable and appropriate, except for the limit on spot market power purchased.
2. Direct MEC to reconsider the limit on power purchased from the spot market to ensure that full advantage can be taken of lower costs, especially in the future when MEC needs to procure greater amounts of supplemental power and when spot market prices are relatively low and stable.

3. Determine that it is inconclusive whether MEC's policies of power supply planning and implementation being implemented prior to 2010 are reasonable and appropriate.

4. Reaffirm that for purposes of the purchased power adjustor, purchased power include only the actual costs of purchased power and associated transmission and reject MEC's unilateral attempt to include ineligible costs.

5. Remove from the 2010 base revenues those costs ineligible for recovery through the purchased power adjustor that MEC has included as purchased power costs in 2010, namely in-house labor costs, consulting costs and legal costs associated with planning and procurement of purchased power.

6. Reduce MEC's purchased power bank balance by $594,737.45 to adjust for the inclusion of these ineligible costs.

7. Disallow MEC's undocumented claim of purchased power expenses of $163,221.69 in 2008, and reduce MEC's purchased power bank balance by that amount.

8. Impose a prudence adjustment of $1.946 million (equal to 1% of MEC's purchased power costs between July 25, 2001 and December 31, 2006) and reduce MEC's purchased power bank balance by that amount.

9. Determine that the actual eligible purchased power costs were adequately documented in 2007, 2009 and 2010.

10. Determine that MEC's actual purchased power costs, adjusted to remove the ineligible and undocumented costs, are prudent and reasonable for 2007-2010.

11. Determine that MEC's objection to providing information prior to 2007 made it impossible to assess whether purchased power costs between July 25, 2001 and December 31, 2006 were prudent and reasonable.

12. Require MEC to file a rate case with purchased power prudence review no later than April 1, 2016, with a test year ending December 31, 2015, so that no more than five years elapses between this rate case and the next rate case to ensure the purchased power cost data and supporting information remains fresh. In addition, require MEC to maintain all files and records pertinent to their purchased power planning and procurement, and to document the prudence of the purchased power expenditures. Should Staff determine that insufficient information is provided; Staff shall recommend that any undocumented and/or unverified costs be denied including interest or that the purchased power adjustor be eliminated.

13. Revise MEC's purchased power adjustor mechanism to use margins on third party sales to offset purchased power costs.

14. Subtract total revenues from third party sales from total cost of purchased power, including power for third party sales, to determine new purchased power costs.

15. Require MEC to file its next rate case no later than April 1, 2016, using a test year of 2015. MEC may file sooner if necessary.

16. Acknowledge that MEC's selection and management of Western to provide critical services are prudent and reasonable.

17. Require MEC to request information regarding AEPCO's marginal operating costs so that regional power dispatch decisions could be made based on actual real time costs rather than average costs over a six-month period.

18. Adopt a base purchased power cost per kWh of $0.087701/kWh.

19. Direct MEC to adjust the bank balance for any ineligible costs that may have been recovered through the purchased power cost adjustor after December 31, 2010.

Q. Does this conclude your direct testimony?

A. Yes it does.

JERRY E. MENDL
President
MSB Energy Associates

AREAS OF EXPERTISE

+ Analysis of energy resource adequacy, cost and availability
+ Evaluation of alternative energy resource options
+ Analysis of electric utility bulk power supplies
+ Analysis of electric utility projected merger savings and implications on system operations and costs
+ Transmission system analysis
+ Service delivery and markets in a restructured electric utility industry

EDUCATION

1973 B.S. Degree in Nuclear Engineering, With Very High Honors, from the University of Wisconsin, Madison, Wisconsin

1974 M.S. Degree in Nuclear Engineering from the University of Wisconsin, Madison, Wisconsin.

EXPERIENCE

1987-Present
President
MSB Energy Associates, Inc.
Middleton, Wisconsin

Since co-founding MSB Energy Associates in 1988, Mendl has served public-sector clients in Arizona, Kentucky, California, Utah, Nevada, Washington, Texas, Alaska, Iowa, Illinois, South Carolina, Connecticut, Massachusetts, Vermont, Maryland, Michigan, Missouri, Minnesota, Louisiana, Wisconsin, Pennsylvania, Georgia, Hawaii, Ohio, New Jersey, the District of Columbia and Ontario. Much of his recent work has involved electric utility restructuring, low-income consumer energy affordability and service issues, prudence of gas and electric utility planning and purchase practices, and analyzing need for transmission lines. He assesses "green pricing" tariffs for renewable electric resources and fuel/purchase power costs for electric and natural gas utility rate cases and renewable energy alternatives for utility construction cases. He evaluates electric utility restructuring alternatives and prepares restructuring policy recommendations and supporting technical information. He analyzes long-range plans and planning methods used by gas and electric utilities. He prepares and presents reports, recommendations and testimony.

He conducted engineering, environmental, economic and life-cycle cost analyses of alternate energy resource options, including improved end-use energy efficiency and renewable resources. Mendl developed state regulatory commission codes for implementing integrated resource planning and evaluated the adequacy of existing and proposed codes. Mendl was both organizer and presenter for a series of five least-cost planning workshops across the U.S. sponsored by the National Association of Regulatory Utility Commissioners (NARUC). He also participated in five Conservation Law Foundation collaborative projects in the northeastern states.

1974-1988

Administrator, Division of Systems Planning, Environmental Review and Consumer Analysis (1979-1988)
Director, Bureau of Environmental and Energy Systems (1976-1979)
Public Service Engineer (1974-1976)
State of Wisconsin, Public Service Commission
Madison, Wisconsin

Mendl was employed by the Wisconsin Public Service Commission for 14 years (1974-1988), and was responsible for the development and evolution of Wisconsin's long-range planning process for electric utilities. He had overall responsibility for directing the Commission's activities concerning utility long-range plans. In addition, Mendl had overall responsibility for and directed the preparation of environmental impact statements and environmental assessments, identifying expected impacts as well as evaluating alternatives, for five large power plants, numerous transmission lines, a major natural gas pipeline, and many policy issues including Electric Space Heat, Electric Utility Tariffs, Electric Sales Promotion, Small- Power Production and Cogeneration, and Extension of Service. Mendl was also responsible for directing the preparation of major studies, including *The Alternative Electric Power Supply Study, Alternative Electric Power Supply - Update*, and *Utility SO_2 Cleanup - Cost and Capability.* (The *Alternative Electric Power Supply Study* and *Update* identified renewable energy, load management and energy efficiency resources that would economically meet Wisconsin's long term electricity needs.) Mendl testified before the Wisconsin Commission in rate cases, planning cases, construction certificate cases and policy cases. He also appeared before other state Commissions and the Federal Energy Regulatory Commission.

OTHER DISTINCTIONS

Mendl staffed the NARUC Subcommittee on Energy Conservation for two and one-half years, and was closely involved with the preparation of the *Least-Cost Planning Handbook for Public Utility Commissioners.*

Mendl also was appointed to serve a four-year term on the Research Advisory Committee of the National Regulatory Research Institute (NRRI). One of seven regulatory staff selected nationally, Mendl helped NRRI to shape its research agenda to be more useful and responsive to the regulatory community.

Mendl is a Registered Professional Engineer in the State of Wisconsin.

TESTIMONY

Mendl, since co-founding MSB Energy Associates in 1988, has testified in the following proceedings:

Submitted To:	Subject	Docket No.	Date
Nevada Public Utilities Commission	Nevada Power and Sierra Power Energy Supply Plans	11-09003, 11-09004	2011
Nevada Public Utilities Commission	Nevada Power and Sierra Power electric fuel and power and Sierra LDC gas cost recovery practices (DEAAs)	11-03003, 11-03004, 11-03005	2011
Nevada Public Utilities Commission	Nevada Power Energy Supply Plan – gas hedging and electric power sales	10-09003	2010

Nevada Public Utilities Commission	Sierra Pacific Power Integrated Resource Plan/Energy Supply Plan	10-07003	2010
Nevada Public Utilities Commission	Nevada Power and Sierra power electric fuel and power cost recovery practices (DEAAs)	10-03003 & 10-03004	2010
Nevada Public Utilities Commission	Nevada Power and Sierra Pacific Power Energy Supply Plan Update	09-07003 & 09-09001	2010
Wisconsin Public Service Commission	Glacier Hills Wind Park application by WEPCo, analyze cost/benefits and RTO dispatch	6630-CE-302	2009
Nevada Public Utilities Commission	Nevada Power electric fuel and power cost recovery practices (DEAA)	09-02029	2009
Nevada Public Utilities Commission	Sierra Power gas and electric fuel and power cost recovery practices (DEAA)	09-02030 & 09-02031	2009
Wisconsin Public Service Commission	Need analysis for 345 kV transmission line proposed by American Transmission Company	137-CE-147	2009
Arizona Corporation Commission	Sulphur Springs Valley Electric Cooperative power procurement review	E-01575A-08-0328	2009
Nevada Public Utilities Commission	Nevada Power Energy Supply Plan Update	08-08030	2008
Nevada Public Utilities Commission	Sierra Power Energy Supply Plan Update	08-08031	2008
Nevada Public Utilities Commission	Sierra Power gas and electric fuel and power cost recovery practices (DEAA)	08-02043 & 08-02044	2008
Nevada Public Utilities Commission	Nevada Power fuel gas and power cost recovery practices (DEAA)	08-02042	2008
Nevada Public Utilities Commission	Westpac Utilities fuel purchase practices and costs (including merging of utility LPG and natural gas rates)	07-05019 & 07-05020	2007
Nevada Public Utilities Commission	Nevada Power Amendment to 2006 IRP and Energy Supply Plan update forward sales proposal	07-07013	2007
Nevada Public Utilities Commission	Sierra Pacific Power approval of 2007 IRP forward sales proposal	07-06049	2007
Nevada Public Utilities Commission	Southwest Gas fuel procurement practices and setting DEAA rate	07-05015	2007
Georgia Public Service Commission	Georgia Power IRP 2007 demand side management plan, energy efficiency and cost tests	24505-U	2007
Nevada Public Utilities Commission	Nevada Power fuel gas and power purchase practices (BTER & DEAA)	07-01022	2007

Nevada Public Utilities Commission	Sierra Pacific Power fuel gas and power purchase practices (BTER & DEAA)	06-12001	2007
Arizona Corporation Commission	UNS Gas prudence of gas procurement practices	G-04204A-05-0831	2007
Nevada Public Utilities Commission	Westpac Utilities fuel purchase practices and costs (BTER & DEAA)	06-05016 & 06-05017	2006
Nevada Public Utilities Commission	Nevada Power Integrated Resource Plan - gas purchase strategies	06-06051	2006
Nevada Public Utilities Commission	Sierra Pacific Power Energy Supply Plan - gas purchase strategies	06-07010	2006
Wisconsin Public Service Commission	Strategic Energy Assessment - electrical adequacy through 2012	5-ES-103	2006
Nevada Public Utilities Commission	Nevada Power fuel gas and power purchase practices (DEAA)	06-01016	2006
Nevada Public Utilities Commission	Sierra Pacific Power fuel gas and power purchase practices (DEAA)	05-12001	2006
Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14717	2006
Michigan Public Service Commission	Consumers gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14716	2006
Nevada Public Utilities Commission	Nevada Power fuel gas and power purchase practices (BTER)	06-01016	2006
Nevada Public Utilities Commission	Sierra Pacific Power fuel gas and power purchase practices (BTER)	05-12001	2006
Nevada Public Utilities Commission	Nevada Power gas purchase practices – Energy Supply Plan	05-9017	2005
Nevada Public Utilities Commission	Sierra Pacific Power gas purchase practices – Energy Supply Plan	05-9016	2005
Michigan Public Service Commission	Consumers gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14403	2005
Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14401	2005
Kentucky Public Service Commission	Analysis of need for and electrical alternatives to EKPC Cranston-Rowan County transmission line	2005-00089	2005
Nevada Public Utilities Commission	Nevada Power gas purchase practices	04-9004	2004
Nevada Public Utilities Commission	Sierra Pacific Power gas purchase practices	04-7004	2004

Nevada Public Utilities Commission	Prudence of Southwest Gas PGA costs, purchase practices	03-12012	2004
Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-13902	2004
Wisconsin Public Service Commission	WPS rate case, low income programs, Weston 4 pre-certification expenses and capital	6690-UR-115	2003
Wisconsin Public Service Commission	Alliant rate case, RiverSide purchase power cost and incentive, Columbia maintenance and outages	6680-UR-113	2003
Wisconsin Public Service Commission	Alliant rate case, RockGen purchase power savings bonus, coal procurement	6680-UR-112	2002
Wisconsin Public Service Commission	Assess fuel and purchase power issues in WPS rate case	6690-UR-114	2002
Wisconsin Public Service Commission	Assess fuel and purchase power issues in MG&E rate case	3270-UR-111	2002
Wisconsin Public Service Commission	Assess renewable energy and other alternative resources in WE Power the Future –Port Washington case	05-CE-117	2002
Wisconsin Public Service Commission	Assess costs related to formation and operation of American Transmission Company	05-EI-129	2002
Wisconsin Public Service Commission	Filed comments in investigation of purchase power incentive mechanisms	05-EI-131	2002
Wisconsin Public Service Commission	Alliant rate case, adequacy of planning, purchase power contracts, coal contracts	6680-UR-111	2002
Michigan Public Service Commission	Analyze proposed gas cost recovery factor and plan, and gas procurement practices.	UR-13060	2002
Wisconsin Public Service Commission	WPS rate case, fuel costs, adequacy of planning, purchase power	6690-UR-113	2002
Wisconsin Public Service Commission	Alliant fuel cost rate case, adequacy of planning, purchase power contracts	6680-UR-110	2001
Wisconsin Public Service Commission	Wisconsin Electric fuel rate case, fuel costs, adequacy of planning, purchase power contracts	6630-UR-111	2001
Wisconsin Public Service Commission	Rulemaking regarding electric utility fuel and purchased power cost recovery	1-AC-197	2001
Wisconsin Public Service Commission	Nuclear spent fuel dry cask storage expansion at Point Beach	6630-CE-275	2000
Wisconsin Public Service Commission	WPS rate case, fuel costs, adequacy of planning, purchase power	6690-UR-112	2000

Wisconsin Public Service Commission	Alliant fuel cost rate case, adequacy of planning, prudence of plant maintenance practices, purchase power	6680-UR-110	2000
Wisconsin Public Service Commission	Rulemaking regarding environmental impact analysis and public input process	1-AC-185	1999
Michigan Public Service Commission	Over-recovery of revenues due to declining coal costs	U-11560	1999
Michigan Public Service Commission	Reasonableness of proposed settlement regarding recovery of nuclear plant replacement power costs through power cost recovery factor, suspension of factor	U-11181-R	1999
Michigan Public Service Commission	Fuel and purchase power surcharge, coal costs	U-11180-R	1998
Vermont Public Service Board	Prudence of Green Mountain Power purchase and management of Hydro-Quebec power	5983	1997
Michigan Public Service Commission	Analysis of coal costs, purchase practices, spot market	U-10971-R	1997
Michigan Public Service Commission	Suspension of the fuel and purchase power factor and planning in the transition to restructured utilities	U-11453	1997
Wisconsin Public Service Commission	IEC merger (of WPL/IES/IPC), need and environmental issues regarding proposed Mississippi River transmission crossings	6680-UM-100	1997
Pennsylvania Public Utility Commission	Restructuring, stranded cost, and securitization -- economic and environmental issues	R-00973877	1997
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of sales promotion	U-11181	1997
Wisconsin Public Service Commission	Primergy merger (of WEPCO/NSP), impact on state regulatory authority	6630-UM-100/4220-UM-101	1996
Michigan Public Service Commission	Gas cost recovery adjustments	U-10640-R	1996
Pennsylvania Public Utility Commission	Electric discounted rates, gas/electric competition	R-943280C0001	1996
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of WEPCO/NSP merger	U-10966	1996
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of energy efficiency	U-10971	1996
Minnesota House Committee on	Impact of cogeneration project on NSP	HF637	1996

Taxes	ratepayers		
Minnesota Senate Committee on Jobs, Energy and Community Development	Impact of cogeneration project on NSP ratepayers	SF1147	1996
Wisconsin Public Service Commission	Role of DSM in Advance Plan-7 in light of potential restructuring	05-EP-7	1995
City Public Service Board of San Antonio	Integrated resource planning process (1992 EPAct hearings)	NA	1994
Maryland Public Service Commission	1992 EPAct rules	8630	1994
Georgia Public Service Commission	Commercial and Industrial DSM programs for Savannah Electric	4135-U	1993
Public Utilities Commission of Ohio	Analysis of forecasts and long range plans for Ohio Power and Columbus Southern (case settled)	90-659-EL-FOR and 90-660-EL-FOR	1990
Georgia Public Service Commission	Integrated resource plan analyses for Georgia Power and Savannah Electric	4131-U and 4134-U	1992
New Orleans City Council	Least-cost planning rules	14629 MCS	1991
District of Columbia Public Service Commission	Potomac Electric least-cost plan analysis	834 Phase II	1990
Massachusetts Department of Public Utilities	Boston Gas plan integrated resource plans	90-55	1990
Massachusetts Department of Public Utilities	Boston Gas commercial and industrial DSM, cost recovery	90-320	1991
Hawaii Public Service Commission	Least-cost resource planning	6617	1991
Georgia Public Service Commission	Least-cost planning and facility certification rules	4047-U	1991
New Jersey Board of Public Utilities Commissioners	Transmission line certificate (case settled)	NA	1990
South Carolina Public Service Commission	Transmission line certificate	88-519-E	1988
Vermont Public Service Board	Least-cost planning	5270	1988
D.C. Public Service Commission	Least-cost planning	834	1987

Mendl also assisted in preparing testimony and testified in numerous cases as a senior staff witness at the Wisconsin Public Service Commission. Dates are approximate.

- Advance Plans 1 through 4 (Dockets 05-EP-1 through 05-EP-4 -- on various occasions between 1977 and 1988) before the Wisconsin Public Service Commission
  A wide variety of planning issues including forecasts, nuclear vs coal power, alternative energy, renewable energy, load management, transmission planning, demand-side management resources, principles and methods of integrated resource planning

- Rate Cases (various occasions between 1976 and 1988) including landmark time-of-use rate case (6630-ER-2) for Wisconsin Electric Power
  Environmental and consumer impacts of rate levels and alternative rate designs before the Wisconsin Public Service Commission

- Construction Cases before the Wisconsin Public Service Commission
  Pleasant Prairie Power Plant (1976-1978)
  Germantown Combustion Turbines (1976-1977)
  Weston 3 (1979)
  Edgewater 5 (1980)
  Apple River -- Crystal Cave Transmission Line (1980)
  Prairie Island -- Eau Claire Transmission Line (1981-1982)
  North Madison -- Huiskamp -- Sycamore Transmission Line (1982)
  Point Beach Nuclear Plant Steam Generator Replacement (1982)
  Wisconsin Natural Gas Pipeline (1986)
  Need for power, appropriateness of the utility proposals, and the comparative economics of alternatives, environmental impacts

- Other Appearances while employed at the Wisconsin Public Service Commission
  Planning investigation before the Connecticut Department of Public Utilities Control Authority (1975); uranium availability and resource alternatives
  Rulemaking proceedings before Wisconsin Legislative Committees (1975-1982); planning, siting, and environmental impact analysis rules
  Tyrone Nuclear Project Termination cost recovery hearing before the Federal Energy Regulatory Commission (1980)
  Acid Rain legislation before Wisconsin Legislative Committees (1984-1985)

Selected Clients

Mendl has served the following public sector clients since 1988.

Client	Nature of Service
Alaska Housing Finance Corporation	Analysis of applicability of EPAct standards to Alaska resource selection process.
American Public Power Association	Prepared whitepaper on distributed resources, "Distributed Resources: Options for Public Power" and presented it to APPA National Meeting and distributed resources workshops.
Arizona Corporation Commission	Analyze UNS Gas fuel procurement practices, provide testimony regarding prudence, and develop auditor training manual. Analyzed Sempra request to be allowed to compete for selected retail loads. Analyzed Sulphur Springs Valley Electric Coop purchase power practices.
California Low Income Governing Board	Analysis of options to deliver energy efficiency and assistance programs to low-income households in a restructured utility environment. Assist Board to develop low-income programs and policies under interim utility administration.
City of Chicago	Evaluate municipalization, especially regarding power availability and cost, transmission constraints, cogeneration potential.
Citizen's Utility Board of	Evaluate energy efficiency and load management programs in light

Wisconsin	of possible industry restructuring. Evaluate fuel rate cases and recommend revenue reductions in testimony for Alliant, Wisconsin Electric, Madison Gas & Electric and Wisconsin Public Service. Assess ATC formation and operation costs. Comment on and develop fuel rules, purchase power incentives. MISO collaborative
Center for Neighborhood Technologies	Analysis of value of avoiding generation, transmission and distribution through energy efficiency, load management and distributed generation.
Clean Wisconsin	Review Strategic Energy Assessments, provide comments to Wisconsin PSC
Conservation Law Foundation of New England	Collaboratives with Boston Edison, United Illuminating, Eastern Utilities Association, and Nantucket Electric regarding system planning approaches, avoided costs, resource screening. Collaborative with Green Mountain Power regarding Vermont Yankee end-of-life planning.
Dane County Energy Collaborative	Technical contractor to collaborative analyzing 345 kV transmission proposal and alternatives to meet Dane County energy needs.
District of Columbia Energy Office	Analysis of DC Natural Gas' and PEPCo's integrated resource planning.
District of Columbia Public Service Commission	Testimony regarding least cost planning principles and rules.
Environmental Law and Policy Center	Analyzed potential impacts of proposed merger of Wisconsin Electric Power Company and Northern States Power Company on state regulatory authority in Wisconsin and Minnesota. Analyzed environmental impacts related to proposed merger of WPL and two Iowa utilities (IES and IPC), including the proposed transmission line crossings of Mississippi River and changes in air pollutant emissions. Analyzed electric and gas energy efficiency plans in Iowa, Illinois, Michigan and Ohio
Environmentalists/Penn. Energy Project	Analyzed PECO application to securitize stranded costs, especially on economic and environmental impacts that could result from authorizing overestimated stranded costs. Analyzed utility retail access pilot programs. Analyzed restructuring plans for PECO and PP&L.
Germantown Settlement, Philadelphia	Advise regarding business structure and market to aggregate load and/or provide energy efficiency and energy assistance services to low-income households.
Georgia Public Service Commission	Developed integrated resource planning and facility certification rules. Developed integrated resource plans and reviewed utility filings. Monitored utility DSM programs. Evaluated GP demand side plan for 2007 IRP. Analyzed DSM selection process in DSM Working Group setting on behalf of Commission Staff.
Hawaii Division of Consumer Advocacy	Developed integrated resource planning rules.
Illinois Citizens Utility Board	Analyzed Illinois electric supply auction, suggested modifications to better incorporate energy efficiency and demand response resources.

Iowa Department of Natural Resources	Developed and implemented workshops to train building operators and architects in energy efficiency and renewable energy resource opportunities.
Kentucky Public Service Commission	Analyzed need and alternatives for an EKPC transmission line and a prepared report. Presented testimony defending and explaining report. Analyzed need and alternatives for an AEP transmission line and a prepared report.
Lake Michigan Coalition	Analyzed nuclear spent fuel dry cask storage expansion proposal
Maryland Public Service Commission	Reviewed two utility long-range plans and suggested improvements.
Massachusetts Division of Energy Resources	Analysis of Boston Gas Co. integrated resource plans and residential energy efficiency programs. Analysis of Boston Gas's commercial and industrial energy efficiency programs.
Michigan Community Action Agency Association	Analysis of Michigan electric utility restructuring proposals and impacts on retail prices. Analysis of MichCon gas cost recovery case and factor. Analyses of Indiana-Michigan, Consumers Energy, Wisconsin Electric and Northern States Power-Wisconsin power supply cost recovery cases and factors, including analysis of coal and power purchase practices, demand-side management, and nuclear plant outage costs. Analysis of Northern States Power/Wisconsin Electric Power Co. proposed merger.
Missouri Public Service Commission	Developed rules for electric resource planning and gas resource planning. Evaluated three electric utility plans filed pursuant to rules.
National Association of Regulatory Utility Commissioners	Organized, prepared and presented at five workshops throughout the U.S. sponsored by NARUC/DOE.
Natural Resources Defense Council, Mid-Atlantic Energy Project Collaborative	Evaluated resource planning and selection processes used by PSE&G to prepare plan filings.
New Jersey Department of the Public Advocate	Analyzed a transmission line application.
City of New Orleans	Developed least cost planning rules, guided a public working group to develop demand-side programs.
Nevada Office of Attorney General, Bureau of Consumer Protection	Sierra Pacific Power and Nevada Power Energy Supply Plans, Base Tariff Energy Rates and Deferred Energy Adjustment Accounts - gas purchase practices and prudence; Southwest Gas and Westpac PGA prudence analysis, gas purchase practices
Nevada Public Utilities Commission, Regulatory Operations Staff	Southwest Gas PGA prudence analysis, gas purchase practices
Northeast States for Coordinated Air Use Management	Electric vehicle analysis.
Ohio Office of Consumer Council	Analyzed two utilities' long-range plans and energy efficiency resource options.

Ontario Energy Board	Evaluated need for natural gas integrated resource planning rules.
The Opportunity Council	Evaluated gas DSM programs to be considered by Cascade Natural Gas in Washington.
Pennsylvania Office of Consumer Advocate	Evaluated demand-side management programs for several electric utilities. Investigated causes of Winter Emergency of 1994. Analyzed electric "flexible rates" and gas/electric competition issues. Analyzed electric reliability concerns in a restructured and competitive market. Evaluated electric energy efficiency plans..
RENEW Wisconsin	Analyzed MG&E's green pricing tariff, compared costs of conventional resources to green resources to determine whether a green premium tariff was appropriate
Responsible Use of Rural and Agricultural Land (RURAL)	Evaluated air and licensing issues related to a proposed power plant. Evaluated Public Service Commission proposed environmental and siting rule changes. Analyzed rules governing environmental review and public comment process and provided testimony before PSCW.
South Carolina Office of Consumer Advocate	Analyzed a transmission line application.
Southeast Wisconsin Energy Initiative	Technical contractor to collaborative analyzing 345 kV transmission proposal and alternatives to meet energy needs in southeastern Wisconsin.
Texas ROSE	Developed electric planning rules. Analyzed city of San Antonio resource plan.
U.S. Environmental Protection Agency	Developed handbook, "Energy Efficiency and Renewable Energy: Opportunities from Title IV of the Clean Air Act", which focuses on how energy efficiency and renewables relate to acid rain compliance strategies.
U.S. Environmental Protection Agency and U.S. Department of Energy	Analyzed and compared utility supply- and demand-side resource selection for Clean Air Act compliance on the Pennsylvania-New Jersey-Maryland (PJM) interconnection.
Utah Committee on Consumer Services	Analyzed DSM cost recovery mechanism, avoided cost methods, cost effectiveness tests, assisted in settlement discussions and would have prepared testimony if issues not settled.
Vermont Natural Resources Council and Vermont Public Interest Research Group	Testimony regarding least cost planning principles and rules.
Vermont Public Service Board	Testimony regarding the prudence of Green Mountain Power's planning and management of the Hydro-Quebec power purchase.
Wisconsin Department of Administration	Analysis of new home characteristics built in northeastern Wisconsin, permit data, survey development and report
Wisconsin's Environmental Decade	Review of Draft Environmental Impact Statement of major 345 kV transmission line in northwestern Wisconsin, develop comments.

EXHIBIT JEM-2

REDACTED

EXHIBIT JEM-3

REDACTED

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
SEPTEMBER 19, 2011**

JM – 3.28 Please describe the current organizational structure for implementation and oversight of Mohave's purchase power procurement method, including:

a) Identify who has responsibility for determining the volumes of purchase power to be procured;
b) Identify who has responsibility for securing bids;
c) Identify who has responsibility for evaluating offers;
d) Identify who has responsibility for deciding to accept or reject offers;
e) Identify the levels of management approval required to enter into a purchase power contract;
f) Identify who has responsibility for implementing a purchase power contract;
g) Identify who has responsibility for Mohave's price risk management activities; and
h) Identify who has ultimate authority for decisions regarding purchase power procurement.

Response:

a) Management in consultation with consultants and Western personnel are responsible for determining the volumes of purchase power to be procured with Management having the ultimate responsibility.

b) Under its agreement with Western, Western personnel have the responsibility for securing bids.

c) In consultation with the consultants for Mohave and Western, the Chief Executive Officer of Mohave has the responsibility for the final evaluation of offers.

d) The Chief Executive Officer of Mohave has the responsibility for deciding to accept or reject offers.

e) The Chief Executive Officer is the level at which approval is required to enter into a purchase power contract and this is accomplished after consultation and review of the dynamics of the proposed contract with Western and the consultants to Mohave.

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
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SEPTEMBER 19, 2011**

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f) Implementation of a purchase power contract after approval and execution is the responsibility of Western under its agreement with Mohave.

g) Responsibility for Mohave price risk management activities is the responsibility of the Chief Executive Officer.

h) Ultimate authority for decisions regarding purchase power procurement is with the Chief Executive Officer who has the responsibility for reporting decisions to the Board.

See Narrative for more detailed discussion.

<u>Prepared by:</u> Michael Curtis/ Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
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Planned Power Procurement Approach and Organization

JM – 3.18 Does Mohave currently have a formal electric purchase power procurement strategy or purchase power supply plan? If yes, please provide a copy.

Response: The Power Supply Planning and Implementation documentation provided in the **Confidential** Attachment JM-3.8 reflects Mohave's effort to formalize the power supply planning process and implementation strategy. The guiding principles reflected in the document have not changed since Mohave became a PRM. However, implementation has changed and will continue to change to allow Mohave to deal with changing conditions. Given the dynamic conditions of the electric utility industry, the strategy and implementation continues to be discussed, reviewed and revised by the Board of Mohave in on-going consultation with Management.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
SEPTEMBER 19, 2011**

JM – 3.19 Did Mohave have a formal electric purchase power procurement strategy or purchase power supply plan when it ceased being an all requirements customer of AEPCO? If yes, please provide a copy.

Response: No, not in the sense of formal written policy statement adopted by its Board of Directors. Mohave adopted a process of securing outside consultants and entities to assist it in power procurement. Mohave was able to benefit from the experience of Western Area Power Administration and their extensive experience in dealing in wholesale power markets. Western provided the framework for implementation of the power supply to serve load. This experience resulted in an informal process which was refined and expanded and eventually resulted in the Power Supply Planning and Implementation document provided in the **Confidential** Attachment JM-3.8.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
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JM – 3.20 Please provide a copy of any updates or amendments Mohave made to its formal electric purchase power procurement strategy or purchase power supply plan between July 25, 2001 and the present. Please identify when those changes occurred and the purpose of those changes.

Response: Mohave continues to follow the principals outlined in the Power Supply Planning and Procurement document in the **Confidential** Attachment JM-3.8 and to implement the processes and procedures which Mohave, Western, and the Consultants have found to be workable for Mohave.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
SEPTEMBER 19, 2011**

JM – 3.27 Please describe when, how, and why Mohave's methods for communicating its written and/or informal procurement strategies to the procurement personnel responsible for the day-to-day electricity purchase decisions changed since July, 25, 2001.

Response: Changes are occurring on a continuous basis in response to changing conditions. Mohave's methods of communicating changes rely on direct communication with the individuals involved consistent with utilizing the Power Supply Planning and Implementation document previously identified and produced in the **Confidential** Attachment JM-3.8. Mohave does not have, and does not believe it necessary to have a formal process documenting the evolution up to its current procurement practices. A primary reason such documentation is unnecessary is that Mohave relies on Western and the procedures and policies that Western utilizes that are periodically reviewed with Mohave and provide the basic framework for the day-to-day operations.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
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JM – 3.29 Please describe when, how, and why Mohave's organizational structure for implementation and oversight of Mohave's purchase power procurement method described in the preceding question changed since July, 25, 2001.

Response: When Mohave became a PRM, Mohave put in place the basic relationship with Western, the consultants, and the Mohave staff. The basic areas of responsibility reflected in this organization structure have not changed significantly since 2001. After the first few years Mohave did place a staff person in Western's office. The objective was to have a Mohave employee become very familiar with Western's activities on behalf of Mohave and to help ensure proper coordination of the activities. Mohave's accounting staff also worked directly with Western and the Consultants in implementing accounting and reporting systems as required.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
SEPTEMBER 19, 2011**

JM – 3.30 How does Mohave monitor the results of its purchase power procurement process, including how it determines whether situational deviations from its policies/procedures are needed?

Response: Mohave monitors with Western and its consultants the results of its purchase power procurement process, including determination of whether or not situational deviations from guidelines, processes, policies and procedures are needed on an incident by incident basis and on a weekly and monthly reporting basis. This monitoring process has existed since July 25, 2001. The process has become easier to implement as Western modified reporting formats to meet Mohave's needs and as Mohave staff became more familiar with Western's procedures.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
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STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
SEPTEMBER 19, 2011**

JM – 3.31 Has Mohave changed its approach to monitoring the results of its purchase power procurement process since July 25, 2001? If so, please describe when, how, and why Mohave modified its approach?

Response: There has not been any significant change in approach. The underlying concepts involve Western, Staff, and Consultants working together. As in any such relationship, the activities become more efficient over time as everyone involved becomes more familiar with processes and reports.

See Narrative for more detailed discussion.

Prepared by: Michael Curtis/ Carl N. Stover

EXHIBIT JEM-6

REDACTED

EXHIBIT JEM-7

REDACTED

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC., FOR VARIOUS AUTHORIZATIONS ASSOCIATED WITH ITS RESTRUCTURING

DOCKET NO. E-01773A-00-0826

DECISION NO. 63868

ORDER

Open Meeting
July 24 and 25, 2001
Phoenix, Arizona

FINDINGS OF FACT

1. On October 11, 2000, Arizona Electric Power Cooperative, Inc. ("AEPCO" or "the Cooperative") filed an application for approval and confirmation of various transactions enabling the Cooperative's restructuring into three affiliated entities. The approvals and confirmations requested include:

A.) Approval of the transfer of AEPCO's transmission assets to Southwest Transmission Cooperative Inc. ("Southwest") and approval of the transfer of its cooperative service provider business to Sierra Southwest Cooperative Services, Inc. ("Sierra").

B.) Approval of AEPCO and Southwest to execute notes, mortgages and assumption and indemnity agreements associated with the restructuring.

C.) Approval of a partial requirements relationship between AEPCO and Mohave.

D.) Approval of the revised Class A member unbundled tariff and the forgiveness of the Purchased Power and Fuel Adjustment Clause.

E.) Confirmation that AEPCO has complied with the requirements of A.C.C. R14-2-1615 by this restructuring.

F.) Approval of waivers or, alternatively, approval of AEPCO's Code of Conduct.

G.) Confirmation that the financial commitment conditions of Decision No. 61932 pertaining to Sierra have been satisfied.

...

43. AEPCO will supply Mohave power and energy based on its historic demand and investment. However, Mohave will be free to procure its additional needs from other sources.

44. Because Mohave will only participate in the wholesale market for its incremental needs, the recent volatility in electric prices should present a minimal risk. In return, the partial requirement arrangement provides Mohave the opportunity to pursue advantageous pricing arrangements as the wholesale market matures and becomes less volatile and chaotic. Therefore, the Partial Requirements Capacity and Energy Agreement should be approved.

Purchased Power and Fuel Adjustor Clause

45. The fundamental rationale for a fuel adjustment clause is that fuel prices can change radically based on the overall energy market. During much of the time that AEPCO's restructuring was being planned, fuel prices were dropping. During the more recent past, there has been a dramatic reversal of that trend. It is likely that for at least the near future, energy prices will be unstable.

46. Purchased power and fuel adjustor clauses for Arizona utilities may be created and set during a rate case wherein a base cost of fuel and purchased power is determined and included in base rates. The base period cost of fuel and purchased power adopted in AEPCO's last rate case and used in the subsequent fuel adjustor filings is \$0.01714 per kWh. AEPCO's most recent filing of its fuel and purchased power cost adjustment indicated that its current cost of fuel and purchased power is \$0.026034.

47. AEPCO's application requested the Commission's approval to: (1) forgive the under-collected balance in its PPFAC bank as of the effective date of the restructuring and (2) to eliminate its PPFAC on an on-going basis.

48. As of December 31, 2000 AEPCO's PPFAC bank balance was undercollected by approximately \$6.7 million. Between January 1 and March 31, 2001, AEPCO has accumulated an additional undercollected balance of \$2.3 million.

49. Staff has not audited the cumulative expenses included in AEPCO's reported undercollected PPFAC balance in several years. Staff cannot confirm the amount undercollected without a complete audit of the historical PPFAC filings, accounting and related invoices.

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**MOHAVE ELECTRIC COOPERATIVE'S RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
NOVEMBER 10, 2011**

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

JMM – 7.15 Refer to Mohave's response to JM-4.14 part b. In-house labor expenses were not booked to Account 557 prior to 2008 and not recovered through the PPCA prior to 2010.

a) What prompted Mohave to book these in-house labor expenses to Account 557 in 2008? Were these new expenses first incurred in 2008? Or were these expenses incurred in prior years but booked to a different account prior to 2008? To which account were they previously booked?

b) Since these in-house labor expenses were not recovered through the PPCA, even though they had been booked to Account 557 beginning in 2008, why did Mohave propose to begin recovering them through the PPCA in 2010? What changed in 2009 or 2010 to cause Mohave to propose to recover in-house labor expenses through the PPCA?

Response:

a) Response to JM4-14 general narrative description and item (f) explain the objectives for booking in-house labor expenses to Account 557. Yes, these expenses were incurred in prior years, beginning in 2001 when Mohave became a Partial Requirements Member, and were booked to account 920.

b) The administration and accounting of Mohave's responsibilities as a Partial Requirements Member continues to be discussed, reviewed and revised by Mohave. The decision to recover in-house labor expenses through the PPCA was made as part of that on-going process.

Prepared by: Dorothy Pierce

**MOHAVE ELECTRIC COOPERATIVE'S RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
NOVEMBER 10, 2011**

Subject: All information responses should ONLY be provided in <u>searchable</u> PDF, DOC or EXCEL files via email or electronic media.

JMM – 7.16 Refer to Mohave's response to JM-4.14 part c. Consulting expenses were not booked to Account 557 prior to 2010, and some were booked to Account 555.11 in 2010, and none of these consulting expenses were recovered through the PPCA prior to 2010.

a) What prompted Mohave to book the consulting expenses to Accounts 557 and 555.11 in 2010? Were these new expenses first incurred in 2010? Or were these expenses incurred in prior years but booked to a different account prior to 2010? To which account were they booked?

b) Since these consulting expenses were not recovered through the PPCA, why did Mohave propose to begin recovering them through the PPCA in 2010? What changed to cause Mohave to propose to recover consulting expenses through the PPCA?

c) Please provide the same information for legal fees as in the previous sub-questions for consulting expenses.

<u>Response</u>:

a) Response to JM4-14 general narrative description and item (f) explain the objectives for consulting expenses to Account 557. Since becoming a Partial Requirements Member of AEPCO, Mohave has relied upon outside consultants to assist with power supply planning and administration. See Narrative provided in **Confidential** DR 3 JM-3.0 Narrative, Sections 2.0 and 3.0. Consulting expenses were incurred in prior years, beginning in 2001 when Mohave became a Partial Requirements Member, and were booked to account 923.

b) The administration and accounting of Mohave's responsibilities as a Partial Requirements Member continues to be discussed, reviewed and revised by Mohave. The decision to recover consulting expenses through the PPCA was made as part of that on-going process.

c) Legal fees were previously booked to Account 923.1. The responses to the sub-questions above are applicable to legal fees.

<u>Prepared by</u>: Dorothy Pierce

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S FOURTH SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
SEPTEMBER 19, 2011**

JM – 4.14 **On page 10, lines 23-24, Mr. Stover includes "administrative and outside service fees associated with the power supply function" as components of wholesale power costs.**

a) Please identify and define the specific costs to which Mr. Stover is referring.

b) Do the administrative costs include any costs, or portions of the costs, of Mohave's internal staff, software, hardware, or facilities that are associated with the power supply function?

c) Please list each "administrative and outside service fees associated with the power supply function" that Mohave included in its purchase power adjustor mechanism, by month for each calendar year in the audit period, July 25, 2001 – December 31, 2010.

d) For each administrative and outside service fee listed above, please describe the amount of the cost, its purpose and to whom it was paid.

e) Please explain why Mohave believes these costs to be part of the wholesale power costs.

f) Please explain why Mohave believes these costs to be part of the costs of purchased power to be recovered through the purchased power adjustor mechanism.

Response: Prior to answering the specific questions, a general narrative description is in order.

Prior to 2001 Mohave was an all requirements member (ARM) of Arizona Electric Power Cooperative ("AEPCO"). AEPCO had the responsibility to:

- Forecast Mohave's future power supply requirements
- Identify the power supply options that could be a part of the power supply portfolio serving Mohave's retail load
- Determine the power supply options that best served the forecasted needs (owned resources, purchased power resources, market purchases)
- Acquire the needed resources
- Operate the resources
- Provide coordination services including scheduling and dispatching
- Arrange for transmission services for delivery of wholesale power supply to the ARMs
- Participate in proceedings in which AEPCO could be impacted by changes in rates charged for services

AEPCO performed these services using AEPCO staff and outside services. Those costs were passed through to Mohave as part of wholesale power

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S FOURTH SET OF DATA REQUESTS
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SEPTEMBER 19, 2011**

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supply and transmission rates. Mohave in turn reflected these costs in the retail rates charged to the member consumers.

Mohave is now a partial requirements member (PRM) of AEPCO. AEPCO's responsibility to the PRM is only to provide the allocated resources to the PRM consistent with the terms of the purchase power agreement. The PRM now has the responsibility to perform all of the services previously provided by AEPCO. The PRM must:

- Forecast future power supply requirements needed to serve the member retail load
- Determine the extent to which the AEPCO allocated capacity is sufficient to serve the load and identify capacity and energy deficiency
- Determine the power supply options available to make certain there are sufficient resources to serve the load
- Acquire the needed resources
- Arrange for the operation of resources
- Arrange for the scheduling and dispatching of the combined power supply portfolio so as to serve the retail load at the lowest cost.
- Arrange for transmission services to deliver capacity and energy to the system.
- Participate in any proceeding or hearings that could impact rates paid for wholesale power supply and transmission services.

Given the variety of activities involved, Mohave must have access to a variety of talents. In some cases the activities are routine, they are very predictable and the associated cost can be determined. Examples include the regular review of invoices and billing from third parties, the review of usage data for billing, daily scheduling and dispatching of resources. In other cases certain events are infrequent and the cost of performing the task is uncertain, such as participation in a wholesale or transmission rate case, negotiation of a power supply agreement, development of a new power supply resources. Starting in 2010, in-house or consulting expenses to be recovered through the PPCA are charged either to Account 555.11 or to Account 557 Other Expenses – Power Supply, and subject to review by the cooperative's auditors.

It is appropriate for Mohave to include all of the costs associated with the power supply function (cost from power supply providers, transmission providers, cost for outside services directly related to the power supply function, and staff costs directly associated with the power supply function) in defining wholesale power supply cost and that this value be used for the reconcilable power supply cost in the fuel and purchase power cost adjuster.

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
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STAFF'S FOURTH SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
SEPTEMBER 19, 2011**

As a result:

1. Mohave would have a complete accounting of all activities associated with the power supply function in a single account (sub accounts).
2. This would be consistent with how wholesale power supply costs were accounted for when AEPCO provided services to Mohave as an ARM.
3. Because the cost for the power supply function is "lumpy," i.e. there will be times when certain activities can be very intense, by including the cost as part of the PPCA Bank, there are two major benefits:
    a. Mohave can effectively spread the recovery of the irregular costs over longer period and effectively "smooth out" the cost.
    b. Mohave does not have to make a change in base rates in order to recover the cost.

Answers to specific questions:

a. An excel spreadsheet has been prepared and labeled Attachment JM-4.14 with a breakdown of the specific costs. The specific costs consist of in house labor and associated benefits and payroll taxes, a small amount of other expenses, and consultant and attorney fees. The types of activities involved include the regular review of invoices and billing from third parties, the review of usage data for billing, daily scheduling and dispatching of resources, participation in a wholesale or transmission rate case, negotiation of a power supply agreement and development of a new power supply resources.

b. Yes. See Attachment JM-4.14 to see the amount of in house labor and associated benefits, payroll taxes and the small amount of other expenses. There were no in house expenses booked to Account 557 prior to 2008. Starting in 2008, expenses were booked to Account 557 in every year. No in house expenses were recovered through the PPCA prior to 2010.

c. Attachment JM-4.14 shows the amount of fees by month by consultant. There were no consulting expenses booked to Account 557 prior to 2010. Some consulting expenses were booked in 2010 in Account 555.11. In the future, all consulting expenses to be recovered through the PPCA will be booked in Account 557. No consulting expenses were recovered through the PPCA prior to 2010.

d. Attachment JM-4.14 shows the amount of fees by month by consultant. The types of activities involved include the regular review of invoices and billing from third parties, the review of usage data for billing, daily scheduling and dispatching of resources, participation in a wholesale or

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
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STAFF'S FOURTH SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
SEPTEMBER 19, 2011**

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transmission rate case, negotiation of a power supply agreement and development of a new power supply resources.

e. Mohave is now a partial requirements member (PRM) of AEPCO. AEPCO's responsibility to the PRM is only to provide the allocated resources to the PRM consistent with the terms of the purchase power agreement. The PRM now has the responsibility to perform all of the services previously provided by AEPCO. The PRM must:

   Forecast future power supply requirements needed to serve the member retail load.

   Determine the extent to which the AEPCO allocated capacity is sufficient to serve the load and identify capacity and energy deficiency.

   Determine the power supply options available to make certain there are sufficient resources to serve the load.

   Acquire the needed resources

   Arrange for the operation of resources

   Arrange for the scheduling and dispatching of the combined power supply portfolio so as to serve the retail load at the lowest cost.

   Arrange for transmission services to deliver capacity and energy to the system.

   Participate in any proceeding or hearings that could impact rates paid for wholesale power supply and transmission services.

f. It is appropriate for Mohave to include all of the costs associated with the power supply function (cost from power supply providers, transmission providers, cost for outside services directly related to the power supply function, and staff costs directly associated with the power supply function) in defining wholesale power supply cost and that this value be used for the reconcilable power supply cost in the fuel and purchase power cost adjuster.

   As a result:
      Mohave would have a complete accounting of all activities associated with the power supply function in a single account (sub accounts).

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S FOURTH SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
SEPTEMBER 19, 2011**

This would be consistent with how wholesale power supply costs were accounted for when AEPCO provided services to Mohave as an ARM.

Because the cost for the power supply function is "lumpy," i.e., there will be times when certain activities can be very intense, by including the cost as part of the PPCA Bank, there are two major benefits:

a. Mohave can effectively spread the recovery of the irregular costs over longer period and effectively "smooth out" the cost.
b. Mohave does not have to make a change in base rates in order to recover the cost.

Prepared by: Carl N. Stover

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MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF MONTHLY COSTS CHARGED TO ACCOUNT 557

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Staff Payroll, Benefits and Payroll Taxes													
2008									4,758.22	4,666.02	10,671.19	2,435.65	22,531.08
2009	8,308.46	7,701.70	8,801.88	6,133.77	6,371.88	12,331.66	5,827.48	6,630.92	9,649.98	11,896.97	13,196.40	8,153.75	105,004.85
2010	12,488.77	23,478.46	9,995.90	4,599.71	6,684.08	6,741.25	10,325.78	10,888.34	8,093.80	9,170.78	8,258.52	9,110.89	119,836.28
Curtis Goodwin et al - Legal													
2008													-
2009													-
2010			58,033.02	13,589.50	50,057.06	38,429.50		57,065.06	35,160.79	34,257.40	56,419.15	17,182.34	360,193.82
Brian Cave - Legal													
2008													-
2009													-
2010									10,000.00				10,000.00
GMD & Associates - Legal													
2008													-
2009													-
2010				3,333.33	6,894.79		6,666.66				6,403.92	5,143.18	28,441.88
CH Guernsey - Consulting (Includes 555.11 in 2010)													
2008													-
2009													-
2010		172.75	7,770.00		17,973.72	12,721.64	16,241.23	8,105.93	4,623.60	9,116.35		(1,194.20)	75,531.02
Expenses (Staff Meeting and Travel)													
2008 *													-
2009 **												353.65	353.65
2010 ***								134.05			304.24	296.16	734.45

TOTAL

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2008 Expenses	-	-	-	-	-	-	-	-	4,758.22	4,666.02	10,671.19	2,435.65	22,531.08
Recovered from PPCA													
2009 Expenses	8,308.46	7,701.70	8,801.88	6,133.77	6,371.88	12,331.66	5,827.48	6,630.92	9,649.98	11,896.97	13,196.40	8,507.40	105,358.50
Recovered from PPCA													
2010 Expenses	12,488.77	23,651.21	75,798.92	21,522.54	81,609.65	57,892.39	33,233.67	76,193.38	57,878.19	52,544.53	71,385.83	30,538.37	594,737.45
Recovered from PPCA	12,488.77	23,651.21	75,798.92	21,522.54	81,609.65	57,892.39	33,233.67	76,193.38	57,878.19	52,544.53	71,385.83	30,538.37	594,737.45

** Expenses (Background Check)
*** Expenses (Staff Meeting and Travel)

Mohave Electric Cooperative, Inc.
C.H. Guernsey
Data Request
Account 557.00 Analysis

Account 557.00

	2007	2008	2009	2010
Payroll Labor	$ -	$ 16,474.33	$ 82,284.50	$ 64,785.02
Total Benefits	$ -	$ 4,089.32	$ 16,132.90	$ 46,633.10
Worker's Comp	$ -	$ 458.88	$ 1,172.08	$ 1,935.36
Payroll Taxes	$ -	$ 1,508.55	$ 5,415.37	$ 6,482.80
Other*	$ -	$ -	$ 353.65	$ 451,886.39
Total	$ -	$ 22,531.08	$ 105,358.50	$ 571,722.67
Audited Trial Balance	$ -	$ 22,531.08	$ 105,358.50	$ 571,722.67
Account 555.10 (2010 Only)				$ 23,014.78
Total recovered through PPCA	$ -	$ -	$ -	$ 594,737.45
***Other Cost Descriptions:**				
Pre-Employment Background Check			$ 353.65	
Legal				$ 398,635.70
Consulting				$ 52,516.24
Meeting and Travel Expense				$ 734.45
Total	$ -	$ -	$ 353.65	$ 451,886.39

**MOHAVE ELECTRIC COOPERATIVE, INC.'S
RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
SEPTEMBER 19, 2011**

JM – 3.8 Please provide any reports, documentation or analyses produced in conjunction with any audits done internally, by independent auditors or regulatory agencies regarding Mohave power purchase function and activities since January 1, 2001.

Response: Since January 1, 2001 there are no reports, documentation or analysis produced in conjunction with any audits done by regulatory agencies concerning the Mohave power purchase function activities.

There have been annual audits by independent auditors. The Audit for the 2009 test year and 2008 were included with the Application as Schedule M. The 2010 audit was provided with Mohave's Supplemental Filing as Supplemental Schedule M. The audit for 2007 is included with Attachment JM-3.8.

Management regularly reports to the Board on power purchases during Board meetings, but these reports are not written. General Counsel has provided two written reports to the Board regarding Mohave power purchase functions and activities. Those are being provided as Confidential documents.

There is a June 18, 2009 Policy of Power Supply Planning and Implementation: Process and Procedures dated April 28, 2009 which is a document in draft form which evolved over time and was placed in written draft form in 2009. The Policy has been a matter of continuous discussion between Mohave Management and the Board of Directors, but the draft acts as general guidance for Mohave employees and its consultants. This is being provided as a Confidential document.

Reference Attachment JM-3.8 for:

a. Audit reports as referenced
b. General Counsel's written reports to Board **[CONFIDENTIAL]**
c. Power Supply Planning and Implementation documentation **[CONFIDENTIAL]**

Prepared by: Michael Curtis

MOHAVE ELECTRIC COOPERATIVE'S RESPONSE TO ARIZONA CORPORATION COMMISSION STAFF'S SEVENTH SET OF DATA REQUESTS TO MOHAVE ELECTRIC COOPERATIVE, INC. DOCKET NO. W-01750A-11-0136 NOVEMBER 10, 2011

Subject: All information responses should ONLY be provided in <u>searchable</u> PDF, DOC or EXCEL files via email or electronic media.

JMM – 7.8 Please refer to Mohave's response to question JM-3.48, specifically Attachment JM-3.48.

a) The monthly bank balance reports (Report FA-1) were not included for the years 2007, 2008 and 2009. Report FA-1 for August 2010 does not include the actual cost of purchased power. Please provide the missing information.

b) The invoices that accompany the January - July 2010 and September - December 2010 sum to be less than the actual cost of purchased power reported on line 3 of the FA-1 reports for the corresponding months. For each month in 2010, please indicate how the actual cost of purchased power reported on line 3 of the FA-1 reports was derived from the invoices provided. If there are invoices missing, please provide them.

c) For each year 2007 – 2010, please provide an executable copy of all spreadsheets that are used to generate the FA-1 reports.

<u>Response</u>:

a) Attachment JMM-3.48 Supplemental_Confidential (2007, 2008, 2009, and 2010) is spreadsheets containing calculations of costs for FA-1 reports and the monthly FA-1 reports submitted to ACC. The values in the files are audited numbers submitted to the ACC following the annual audit.

b) See Attachment JMM-3.48_Supplemental_Confidential 2010, worksheet "PPA_Adj" for monthly costs of purchased power reported on line 3 of the FA-1 reports.

c) See response to (a) above.

<u>Prepared by</u>: Dorothy Pierce

**MOHAVE ELECTRIC COOPERATIVE INCORPORATED'S
RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S NINTH SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
December 9, 2011**

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

Regarding 2008 Fuel Bank Report and Documentation

JEM – 9.14 Please refer to spreadsheet Line 24, "Transmission- Firm Transm. Svc WAPA", the values for June through November are not supported by invoices or other documentation in Attachment JM-3.48 2009.Please provide the supporting documentation (e.g., invoices, receipts).

Response: See Attachment JEM-9.14 CONFIDENTIAL with invoices for June 2008 through December 2008.

Prepared by: Dorothy Pierce

EXHIBIT JEM-13

REDACTED

EXHIBIT JEM-14

REDACTED

EXHIBIT JEM-15

REDACTED

EXHIBIT JEM-16

REDACTED

**MOHAVE ELECTRIC COOPERATIVE'S RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
NOVEMBER 10, 2011**

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

JMM – 7.6 Referring to the response to JM-3.42 in the preceding question, please clarify what is meant by the statement "a function of variable cost" in regards to Western's decision to schedule energy.

a) Is it AEPCO's variable production cost, including transmission cost, compared to market cost, including transmission (where the market cost may include some fixed costs the seller hopes to recover)?

b) Is it the variable cost as faced by Mohave, which would be the ACC approved energy rate for AEPCO resources and the market price of energy, both including transmission?

c) Please explain which variable costs Western considers in its dispatch of resources to serve Mohave's needs.

d) Is the same variable cost comparison used by Western to make scheduling decisions for Third Party Sales on Mohave's behalf? Please explain whether and how scheduling decisions by Western for Mohave's native load and Mohave's Third Party Sales would differ.

Response: a) If the reference to AEPCO variable production cost means cost incurred in an interval for a particular resource, this information is not available to the PRM. AEPCO does not provide real time variable production cost by interval.

b) The information available to the PRM in making a dispatch decision is the ACC approved effective energy rate (Energy Charge + PPFAC), the applicable AEPCO transmission rate, plus additional information available as described below.

c) Mohave does not have interval production cost data to make dispatch decisions. Mohave does have the ACC approved energy rates and the ACC approved transmission rates. In addition, Mohave has monthly fuel cost reports prepared by AEPCO and provided to the ACC. The fuel cost reports are typically available approximately 60 days after the end of the month. The reports show average cost data for the Base and Other resources for the reporting month. The reports also show other cost components that are part of the PPFAC and which can result in changes in the PPFAC. This information is used by Mohave to estimate trends in resource costs. Mohave will then determine the strike price used for making scheduling decisions. Currently, the primary focus is on the estimated Base Resource cost which is developed using the ACC approved Base energy charge, Base FFPAC charge, ACC approved transmission cost, losses, and information from the AEPCO fuel report.

d) Western utilizes the same information for making scheduling decisions for native load and third party sales with the exception of adjustments for transmission cost and losses, where applicable.

MOHAVE ELECTRIC COOPERATIVE'S RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
NOVEMBER 10, 2011

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

Prepared by: Carl N. Stover

**MOHAVE ELECTRIC COOPERATIVE, INCORPORATED'S
RESPONSE TO
ARIZONA CORPORATION COMMISSION
STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. W-01750A-11-0136
DECEMBER 9, 2011**

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

JEM – 8.8 Spreadsheet Lines 32, 33 and 34 subtract the purchase power costs made to entities who [are] not subject to the purchase power adjustor. While this yields the purchased power costs subject to the PPA, it is unclear how the margins on non-PPA sales are flowed through to MEC's retail customers. Please explain in detail how the margins (revenues from non PPA sales minus the cost of power for non-PPA sales) offset the rates paid by MEC's retail ratepayers. Please provide your calculations.

Response: Mohave's third party sales are limited to either AES Sales or AES Energy Exchanges. The cost of purchased power (power supply + transmission) for third party sales is subtracted from the purchased power cost prior to calculating the PPA applied to Mohave members.

All margins end up in the members' patronage capital credit account and show as a liability on the Cooperative's balance sheet. Cash from positive margins associated with third party sales is available to fund construction or operations, thereby minimizes the necessity for funds through debt or rate increases. In the pending rate proceeding, Mohave has included $309,874 in margins from third party sales in its adjusted test year calculations and reduced the requested increase by that amount. See Schedules, F.4.1, F-4.0 p. 7, A-20, p.1 and A-1.0. If these margins are flowed back through the PPA, then the $2,980,757 requested increase would be increased to $3,290,631 (10.4% additional revenue).

Prepared by: Dorothy Pierce

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MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED TEST YEAR RESALE REVENUE AND POWER COST
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2009

		January	February	March	April	May	June	July	August	September	October	November	December	Total
Excess Baseload Energy														
Available Baseload Energy	(MWh)	92,249	83,367	48,064	91,757	94,700	96,850	100,048	100,175	96,679	92,250	89,306	92,297	1,077,742
Baseload Energy Used for Load	(MWh)	45,103	41,110	42,568	45,771	68,394	67,029	86,366	80,488	71,787	48,953	42,726	51,154	691,449
Total Excess Baseload Energy	(MWh)	47,146	42,257	5,495	45,986	26,306	29,821	13,682	19,687	24,892	43,297	46,580	41,143	386,292
Total Excess % of Total Available		51%	51%	11%	50%	28%	31%	14%	20%	26%	47%	52%	45%	36%
5x8 Excess Baseload Energy	(MWh)	12,687	11,564	1,020	11,140	1,533	3,551	5	476	1,433	9,439	11,547	11,919	76,314
5x8 Excess % of Total Available		27%	27%	19%	24%	6%	12%	0%	2%	6%	22%	25%	29%	20%
Potential Products														
Possible 5x8 Excess product @ 99.5% Threshold	(MW)	40.0	45.0	-	10.0	-	-	-	-	-	12.5	50.0	40.0	
Associated Energy	(MWh)	8,000	8,280	-	2,080	-	-	-	-	-	2,500	9,600	8,640	39,100
% of 5x8 Excess Utilized in Product		63%	72%	0%	19%	0%	0%	0%	0%	0%	26%	83%	72%	51%
% of Total Excess Utilized in Product		17%	20%	0%	5%	0%	0%	0%	0%	0%	6%	21%	21%	10%
Forwards			Q1			Q2			Q3			Q4		
Forwards [Enter SuperPk Adder, either 1 or 2]		36.11	35.30	35.20	35.50	35.35	37.05	48.40	46.65	40.65	39.45	38.30	41.45	
Adder for Delivery to Mead		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	
Adder for SuperPeak Product	0.20	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	
Total		46.93	46.12	46.02	46.32	46.17	47.87	59.22	57.47	51.47	50.27	49.12	52.27	
Margin for Third Party Sales														
Energy Sales kWh		12,687,297	11,564,178	1,019,632	11,140,470	1,533,052	3,550,709	4,521	475,844	1,433,371	9,438,757	11,546,702	11,918,986	76,313,520
Revenue $		595,440.21	533,363.01	46,925.51	516,048.85	70,784.07	169,979.55	267.76	27,347.71	73,778.47	474,505.21	567,197.09	623,029.25	3,698,666.69
Cost of Power $		563,394.38	513,520.96	45,277.97	494,705.71	68,076.97	157,673.43	200.77	21,130.42	63,650.52	419,139.16	512,744.92	529,276.65	3,388,791.87
Margin $		32,045.83	19,842.05	1,647.54	21,343.14	2,707.10	12,306.12	66.99	6,217.29	10,127.95	55,366.05	54,452.17	93,752.60	$\boxed{309,874.82}$
Margin $/kWh		0.002526	0.001716	0.001616	0.001916	0.001766	0.003466	0.014817	0.013066	0.007066	0.005866	0.004716	0.007866	0.004061

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MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF ADJUSTED 2010 RESALE (TPS) REVENUE AND POWER COST
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2010

		January	February	March	April	May	June	July	August	September	October	November	December	Total
Excess Baseload Energy														
Available Baseload Energy	(MWh)	92,249	83,367	48,064	91,757	94,700	96,850	100,048	100,176	96,679	92,250	89,306	92,297	1,077,742
Baseload Energy Used for Load	(MWh)	45,103	41,110	42,569	45,771	68,394	67,029	86,366	80,488	71,787	48,953	42,726	51,154	691,449
Total Excess Baseload Energy	(MWh)	47,146	42,257	5,495	45,986	26,306	29,821	13,682	19,687	24,892	43,297	46,580	41,143	386,292
Total Excess % of Total Available		51%	51%	11%	50%	28%	31%	14%	20%	26%	47%	52%	45%	36%
5x8 Excess Baseload Energy	(MWh)	12,687	11,564	1,020	11,140	1,533	3,551	5	476	1,433	9,439	11,547	11,919	76,314
5x8 Excess % of Total Available		27%	27%	19%	24%	6%	12%	0%	2%	6%	22%	25%	29%	20%
Potential Products														
Possible 5x8 Excess product @ 99.5% Threshold	(MW)	40.0	45.0	-	10.0	-	-	-	-	-	12.5	50.0	40.0	
Associated Energy	(MWh)	8,000	8,280	-	2,080	-	-	-	-	-	2,500	9,600	6,640	39,100
% of 5x8 Excess Utilized in Product		63%	72%	0%	19%	0%	0%	0%	0%	0%	26%	83%	72%	51%
% of Total Excess Utilized in Product		17%	20%	0%	5%	0%	0%	0%	0%	0%	6%	21%	21%	10%
Forwards			Q1			Q2			Q3			Q4		
Forwards [Enter SuperPk Adder, either 1 or 2]		36.11	35.30	35.20	35.50	35.35	37.05	48.40	46.65	40.65	39.45	38.30	41.45	
Adder for Delivery to Mead		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	
Adder for SuperPeak Product	0.20	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82	
Total		46.93	46.12	46.02	46.32	46.17	47.87	59.22	57.47	51.47	50.27	49.12	52.27	
Margin for Third Party Sales														
Energy Sales kWh		12,687,297	11,564,178	1,019,632	11,140,470	1,533,052	3,550,709	4,521	475,844	1,433,371	9,438,757	11,546,702	11,918,986	76,313,520
Revenue $		595,440.21	533,363.01	46,925.51	516,048.85	70,784.07	169,979.55	267.76	27,347.71	73,778.47	474,505.21	567,197.09	623,029.25	3,698,666.69
Cost of Power $		535,827.74	488,394.61	43,062.54	470,499.99	64,746.00	149,958.54	190.95	20,096.52	60,536.13	398,630.87	487,656.54	503,379.38	3,222,979.80
Margin $		59,612.47	44,968.40	3,862.97	45,548.86	6,038.07	20,021.01	76.81	7,251.19	13,242.34	75,874.34	79,540.55	119,649.87	$\boxed{475,686.89}$
Margin $/kWh		0.004699	0.003889	0.003789	0.004089	0.003939	0.005639	0.016990	0.015239	0.009239	0.008039	0.006889	0.010039	0.006233

EXHIBIT JEM-19

REDACTED

EXHIBIT JEM-20

REDACTED

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF PROPOSED PPCA BASE COST - 2010 DATA

	Adjusted 2010	Proposed 2010	Difference
Total kWh Sales	655,743,735	655,743,735	0
Less Lighting kWh Sales	1,100,103		(1,100,103)
Jurisdictional kWh Sales	654,643,632	655,743,735	1,100,103
Purchased Power	58,579,697	58,579,697	0
Power Cost per kWh Sold	0.089483	0.089333	(0.000150)
Authorized Base Cost	0.065798	0.091183	0.025385
Average PPCA Factor	0.023685	(0.001850)	(0.025535)

Adjusted 2010 Power Cost on Supplemental Schedule F-7.0
Adjusted 2010 kWh Sales on Supplemental Schedule F-2.0
Note: PPCA to be charged on lighting under new rates

EXHIBIT JEM-22

REDACTED

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF) MOHAVE ELECTRIC COOPERATIVE, INC. FOR) A DETERMINATION OF THE FAIR VALUE OF) ITS PROPERTY FOR RATE MAKING PRUPOSES,) TO FIX A JUST AND REASONABLE RETURN) AND TO APPROVE RATES DESIGNED TO) DEVELOP SUCH A RETURN)	DOCKET NO. E-01750A-11-0136

DIRECT

TESTIMONY

OF

CANDREA ALLEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 12, 2012

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EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01750A-11-0136

Staff's testimony contains recommendations regarding Mohave Electric Cooperative, Inc.'s proposed modifications regarding its Service Rules and Regulations and Rates and Charges for Other Services.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Candrea Allen. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

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

A. I am employed by the Utilities Division ("Staff") of the Arizona Corporation Commission as a Public Utilities Analyst. My duties include evaluation of various utility applications and review of utility tariff filings. I have been employed by the Arizona Corporation Commission since August 2006.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01750A-11-0136?

A. Yes.

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

A. My testimony provides Staff's analysis and recommendations regarding the proposed changes to Mohave Electric Cooperative, Inc.'s ("Mohave") Rates and Charges for Other Services and Service Rules and Regulations.

RATES AND CHARGES FOR OTHER SERVICES

Q. What changes has Mohave proposed to its current standard offer tariff-rates and charges for other services?

A. Mohave is proposing to revise its Regular Hours - Establishment, Re-Establishment, and Reconnection Fees. Currently Mohave charges an Establishment Fee of $25.00, a Reconnection Fee of $25.00, and a Re-Establishment Fee of $50.00. Mohave is proposing to increase the Establishment and Reconnection Fees to $40.00 from the current $25.00 and decrease the Re-Establishment Fee to $40.00 from the current $50.00.

In addition, Mohave is proposing to revise its After Hours - Establishment, Re-Establishment, and Reconnection Fees. For After Hours service, currently Mohave's charges an Establishment Fee of $50.00, a Reconnection Fee of $50.00, and a Re-Establishment Fee of $75.00. Mohave is proposing to increase the Establishment and Reconnection Fees to $60.00 from the current $50.00 and decrease the Re-Establishment Fee to $60.00 from the current $75.00.

Q. Has Mohave made any other revisions to its proposed Standard Offer Tariff-Rates and Charges for Other Services?

A. Yes. As a response to Staff's Data Request, Mohave revised the structure of its Standard Offer Tariff-Rates and Charges for Other Services (see Exhibit CA-5.6(b)). Mohave indicated that it does not distinguish between service establishment, re-establishment, and reconnection fees. Therefore, Mohave's proposed Standard Offer Tariff-Rates and Charges for Other Services as revised, eliminates the redundancies in categorizing the fees. Mohave's proposed Standard Offer Tariff-Rates and Charges for Other Services as revised only distinguishes between the proposed Regular Hours and After Hours fees for these services.

In addition to the revisions described above, Mohave is proposing to revise the following fees included in its Standard Offer Tariff-Rates and Charges for Other Services:

Service Fee	Current Fee Amount	Proposed Fee Amount
Meter Re-Read*	$5.00	$25.00
Meter Test Shop Test Independent Lab Test**	 $10.00 $25.00	 $40.00 $40.00
Insufficient Funds	$15.00	$25.00
Finance Charge***	15%	1.5%
Late Fee Penalty	0	1.5%
Interest on Customer Deposits****	6%	One Year Treasury Constant Maturities Rate
Service Availability Charge	8%	0
Customer Information Charge	0	$50.00

*No charge for read error
**Lab Costs are in addition to the fee
***Charged to customers on the Deferred Payment Plan
****Established on the first business day of the year, as published by the Federal Reserve

Mohave is also removing the reference to the Pole Attachment Rental fee. This fee is charged for the use of its poles by third parties (i.e. cable companies). It is not for utility services and is not set by the Commission.

Q. Did Mohave provide justification for proposing to revise its Rates and Charges for Other Services?

A. Mohave provided information regarding the costs incurred for each service above, with the exception of the Customer Information Charge. The proposed Customer Information Charge would be charged when Mohave is requested to gather information not readily available from its system. These requests would not include typical billing information requests from customers, but rather consumption data requests from power consultants and organizations that would require Mohave to obtain large volumes of information to satisfy such a request. However, Mohave did not provide a cost-based justification for the proposed Customer Information Charge. In addition, Mohave indicated that such requests for information are historically not a frequent occurrence (see Exhibit CA-5.27).

The cost information Mohave did provide related to the other proposed Rates and Charges for Other Services indicates that Mohave would recover a greater portion of its costs but not all of the costs incurred. Staff believes that the proposed charges are appropriate. Therefore, Staff recommends approval of Mohave's proposed Standard Offer Tariff-Rates and Charges for Other Services, as specified in the revision attached as Exhibit CA-5.27, excluding the Customer Information Charge.

Q. Please describe Mohave's proposed changes to its Credit Card Payment Rate Schedule.

A. Further, Mohave has proposed revisions to its current Credit Card Payment Rate Schedule (Exhibit CA-5.21). Mohave is not proposing any changes except to rename the tariff Alternative Payment Rate Schedule, eliminate reference to credit card payments and add reference to alternative payments which would include all payment methods other than cash or check (including cashier's check and certified check), and clarify the reference to the potential bank transaction fee. Should a financial institution not charge a fee to Mohave, the fee would not be charged to Mohave's customers. Staff recommends that Mohave's proposed revisions to its Alternative Payment Rate Schedule be approved.

SERVICE RULES AND REGULATIONS

Q. Has Mohave proposed any modifications to its Service Rules and Regulations?

A. Yes. Mohave has proposed several changes to its Service Rules and Regulations. Many of the proposed changes are substantive, but there are a few proposed changes that are merely clarifications. Staff will only be addressing the substantive revisions proposed by Mohave.

Section 102-Establishing Electric Service

Q. Did Mohave propose prepaid metering in its Service Rules and Regulations?

A. Yes. Mohave has proposed to include prepaid metering as a subsection of Section 102-Establishing Electric Service of its Service Rules and Regulations. In its application, Mohave did not provide any analysis relating to the implementation of prepaid metering. Staff does not believe Mohave's proposal provides adequate information regarding the payment option. Although Mohave did provide responses to Staff's data requests pertaining to its prepaid metering option, Staff believes that approval of prepaid metering would be premature at this time. Staff believes that Mohave should engage in discussions with stakeholders and other interested parties to further evaluate and assess its proposal. In addition, Staff believes that Mohave would benefit from modeling its proposal after the Sulphur Springs Valley Electric Cooperative, Inc.'s ("SSVEC") application for its Experimental Pre-Paid Residential Tariff (Docket E-01575A-11-0439). Staff recommends that Mohave remove SubSection 102-I: Prepaid Metering from its proposed Service Rules and Regulations at this time. If Mohave wishes to pursue a pre-pay option, Staff recommends that Mohave file, in a separate docket, an application for Commission approval of prepaid metering.

Section 106-Line Extensions to Individuals and Section 107-Construction of Line Extensions within Subdivisions

Q. Please explain the changes Mohave is proposing to its current line extension allowance policies.

A. Currently, for individuals not located within a subdivision, Mohave offers 625 feet of free footage allowance to individuals requesting a single-phase line extension and 225 feet of free footage allowance to individuals requesting a three-phase line extension. Mohave is proposing to offer an allowance of $1,750 for single phase line extensions and $2,500 for three phase line extensions.

In addition, for line extensions within a subdivision, Mohave's current free footage allowance is 500 feet for single-phase line extensions and 225 feet for three-phase line extensions. Mohave is proposing to offer an allowance of $800 for single-phase line extensions and $2,500 for three-phase line extensions.

Mohave states that a line extension allowance based on an actual footage does not account for inflation, deflation, and increases in the cost of materials. Further, Mohave states that a line extension allowance based on a dollar amount allows for adjustments during periods of inflation and deflation. The tables below compare Mohave's current and proposed line extension allowance for individuals not within a subdivision and within a subdivision.

Not within a Subdivision

	Current LEP*	Equivalent Dollar Amount-Current	Proposed LEP*	Equivalent Footage Amount-Proposed
Single-Phase	625 feet	$5,913	$1,750	132 feet
Three-Phase	225 feet	$3,195	$2,500	108 feet

***LEP-Line Extension Policy**

Within a Subdivision (Paid by the Developer)

	Current LEP*	Equivalent Dollar Amount-Current	Proposed LEP*	Equivalent Footage Amount-Proposed
Single-Phase	500 feet	$2,390	$800	167 feet
Three-Phase	225 feet	$5,171	$2,500	109 feet

***LEP-Line Extension Policy**

Q. Does Staff agree with Mohave's proposed revisions?

A. Staff does agree that a line extension policy based on a dollar amount would provide greater flexibility during periods of economic fluctuations. In addition, Staff believes that Mohave's proposed line extension allowance would be beneficial for its customers. However, Mohave is proposing to include the cost of a transformer as part of the proposed line extension allowance amount for individuals not within a subdivision. Staff does not believe that individual applicants should pay for the cost of a transformer (See Staff recommendations in the Arizona Public Service Company application for approval of Version 12 of Service Schedule 3 and Agreement, Docket No. E-01345A-11-0207). With Staff's proposal, a single-phase line extension allowance of $1,750 would equate to approximately 185 feet and a three-phase line extension allowance of $2,500 would equate to approximately 176 feet. This is compared to 132 feet and 108 feet respectively under Mohave's proposal. Therefore, Staff recommends that Mohave not include the cost of the transformer for individuals not within a subdivision requesting single-phase or three-phase service. In addition, Staff recommends that Mohave's proposed revisions to single-phase and three-phase line extension allowances within a subdivision be approved.

Staff further recommends that any potential customer who has been given the current line extension free footage allowance estimate or quote by Mohave up to one year prior to an Order in this matter should be given the line extension free footage allowance as specified in Mohave's current Service Rules and Regulations.

Section 111-Termination of Service

Q. Please explain Mohave's proposed changes to SubSection 111-A.

A. Mohave has proposed to modify language in its Service Rules and Regulations that would result in inconsistencies with the Arizona Administrative Code ("A.A.C.") by removing specific guidelines that Arizona Electric Utilities are required to follow.

Mohave has proposed to remove A.A.C. R14-2-211.A.3 from its Service Rules and Regulations. A.A.C. R14-2-211.A.3 specifies that a Utility cannot disconnect service to customers for "[n]nonpayment of a bill for another class of service." In addition, Mohave has proposed language in its proposed Service Rules and Regulations that differs from the Commission's Rules regarding termination of residential service A.A.C. R14-2-211.B.3 where the customer has the inability to pay (A.A.C. R14-2-211.A.5.a and A.A.C. R14-2-211.A.5.b.). In addition, Mohave has proposed to remove A.A.C. R14-2-211.A.6.b, which refers to notifying a third party previously designated by the customer of a pending disconnect. Mohave has indicated that it has no objection to including the language in its proposed Service Rules and Regulations. Staff notes that there is a minor reference error on page 46 of Mohave's proposed Service Rules and Regulations (Point 1.f. should reference c. and d. respectively). Staff believes that Mohave's proposals conflict with the Commission's Rules. Therefore, Staff recommends that Mohave be required to file revised Service Rules and Regulations which include the language referenced above.

The following is information that has not been included in Mohave's proposed Service Rules and Regulations:

- A.A.C. R14-2-211.B.3 which refers to maintaining records of terminations of service without notice;
- A.A.C. R14-2-211.C.2 which refers to maintaining records of terminations with notice;
- A.A.C. R14-2-211.D.2.d which refers to the minimum information that must be included in advance written notice of disconnection from Utility;
- A.A.C. R14-2-211.E.4 which refers to a personal visit from a representative from the Utility in order to disconnect service with notice; and
- A.A.C. R14-2-211.E.5 which refers to the Utility's right to remove its property from a customer's premises

Decision No. 57172 dated November 29, 1990, approved Mohave's current Service Rules and Regulations with the exclusion of the above requirements. Staff recommends that the above guidelines should be included in Mohave's proposed Service Rules and Regulations.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A.

1. Staff recommends approval of Mohave's proposed Standard Offer Tariff-Rates and Charges for Other Services, as specified in the revision attached as Exhibit CA-5.6(b) of this testimony, except for the proposed Customer Information Charge.

2. Staff recommends approval of Mohave's Alternative Payment Rate Schedule as revised in Exhibit CA-5.21, of this testimony.

3. Staff recommends that Mohave remove's Prepaid Metering not be approved at this time, as discussed in this testimony.

4. If Mohave wishes to pursue a pre-pay option, Staff recommends that Mohave file in a separate docket, an application for Commission approval of prepaid metering, as discussed in this testimony.

5. Staff recommends that Mohave not charge the cost of the transformer to individuals not within a subdivision requesting single phase or three phase service, as discussed in this testimony.

6. Staff recommends that Mohave's proposed revisions to single phase and three phase line extension allowances within a subdivision be approved, as discussed in this testimony.

7. Staff further recommends that any potential customer who has been given the current line extension free footage allowance estimate or quote by Mohave up to one year prior to an Order in this matter should be given the line extension free footage allowance as specified in Mohave current Service Rules and Regulation, as discussed in this testimony.

8. Staff recommends that Mohave be required to file revised Service Rules and Regulations which include the language from the Arizona Administrative Code as discussed in this testimony.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MOHAVE ELECTRIC COOPERATIVE, INC.

1999 Arena Drive
Bullhead City, Arizona 86442
Filed By: J. Tyler Carlson
Title: CEO/General Manager

Effective Date: ____________________

STANDARD OFFER TARIFF

RATES AND CHARGES FOR OTHER SERVICES

Rate

OTHER SERVICE CHARGES

Establishment of Service-Regular Hours (Incl. Re-Establishment & Reconnection)		$40.00
~~Establishment of Service~~ After Hours Service		$60.00
~~Re-Establishment of Service-Regular Hours~~		~~$40.00~~
~~Re-Establishment of Service-After Hours~~		~~$60.00~~
~~Reconnection of Service-Regular Hours~~		~~$40.00~~
~~Reconnection of Service-After Hours~~		~~$60.00~~
Meter Re-Read Charge	(No Charge for Read Error)	$25.00
Meter Test Charges:		
	(a) Shop Test	$40.00
	(b) Independent Lab Test	$40.00 Plus Lab Cost
Insufficient Funds Payment		$25.00
Finance Charge-Deferred Payment Plan (Monthly)		1.50%
~~Finance Charge-Delinquent Balances~~Late Fee Penalty (Monthly)		1.50%
Credit Card Service Charge	(Percentage of Total Payment)	~~3.00%~~Applicable Service Charge
Interest Rate on Customer Deposits		~~Annual Three Month Commercial Paper~~ One Year Treasury Constant Maturities Rate Established Annually Each January 1
~~Pole Attachment Rental~~		~~$21.21~~
Service Availability		$0.00
Customer Information Charge		$50.00

ELECTRIC RATES

RATES AND CHARGES FOR OTHER SERVICES

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the service sold hereunder.

Other Charges

Other charges may be applicable subject to approval by the Arizona Corporation Commission.

RESPONSE-CA-5.21

MOHAVE ELECTRIC COOPERATIVE, INC

~~CREDIT CARD~~ALTERNATIVE PAYMENT RATE SCHEDULE

Type of Service

This tariff permits Cooperative Members/Consumers to pay for Mohave Electric Cooperative's sales and services by means other than cash, check drawn on the Consumer's account maintained at a "bank" (as defined by A.R.S. § 47-4105), cashier's check or certified check. Alternative Payment includes, but is not necessarily limited to, credit cards and debit cards. ~~of credit card ("Mastercard, "Visa", and "Discover") rather than cash, check or currently accepted method of payment.~~ ~~Offering this optional method of payment responds to changes in the Consumers lifestyle and in acceptable good business practices. Payment by credit card is an alternative and optional method of paying for services and sales provided by the Cooperative.~~

Availability

Alternative Payment ~~by credit card~~ shall be available to all Mohave Electric Cooperative Members/Consumers receiving sales and services provided by Mohave Electric Cooperative. ~~Only "Mastercard", "Visa", or "Discover" credit cards will be accepted.~~

Optional Method of Payment

Alternative Payment ~~by credit card~~ is purely optional for the Consumer. The Cooperative will continue to accept cash, check drawn on the Consumer's account maintained at a "bank" (as defined by A.R.S. § 47-4105), cashier's check or certified check.~~; all other forms of payment normally used by the Cooperative will be maintained.~~

Extra Charge Involved

The use of ~~credit cards for~~ Alternative ~~p~~Payments is administered by a local bank. The bank charges a service charge for each transaction. In order to maintain its financial integrity and to ensure Consumers using ~~this optional payment plan~~ Alternative Payment pay the cost thereof, the Cooperative may pass through the bank's ~~a~~ service charge to the Consumers utilizing the service. The Cooperative may add to all ~~credit card payments~~Alternative Payments the ~~current~~ service ~~fee~~ charge~~which is reflected as a percentage of the total bill paid~~ (hereinafter "bank ~~percentage~~ transaction charge").

Awareness of Transaction Charge

In order to assure that Consumers desiring to use a credit card for payment are aware of the extra charge:

1. All Cooperative publicity dealing with the availability of payment by credit cards will indicate that ~~credit card payments~~Alternative Payments may have the current ~~percentage~~ bank transaction charge added to the payment.
2. Cooperative personnel will be instructed that whenever discussing the availability of the ~~credit card payment~~Alternative Payment option with a Consumer, they will inform the Consumer that ~~a~~the current bank ~~percentage~~ transaction charge may be added to the payment; and
3. The current bank ~~percentage~~ transaction charge (added as a transaction cost) will be reflected in the Consumer's copy of his/her credit card receipt.

Conditional Acceptance of Payment

Payment by credit card shall not be deemed accepted by the Cooperative unless and until accepted and paid by the issuing bank. Any card found to be dishonored shall be immediately deemed rejected by the issuing bank and the Consumer's account status shall be the same as if no payment were tendered.

ARIZONA CORPORATION COMMISSION
STAFF'S FIFTH SET OF DATA REQUESTS TO
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. W-01750A-11-0136
SEPTEMBER 21, 2011

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

The Following Questions Relate to the Proposed Rates and Charges for Other Services

CA – 5.27 Please specify the costs, if any, associated with the Customer Information Charge that were incurred by Mohave in 2009 and 2010. In addition, please explain why Mohave did not include this charge in Schedule N-3.1 of the application.

Response: **Mohave did not track time or costs associated with customer information requests in 2009 and 2010. The Cooperative estimates that one to two hours were spent on each request, and this could increase due to the legacy system reference.**

Mohave proposes this charge as a new charge. Customer information requests of this type historically have been rare, however requests of this type are increasing, especially for Cooperative's commercial customers.

Prepared by: **A. Lauxman, CFO**
Mohave Electric Cooperative, Incorporated

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INCORPORATED, AN ELECTRIC COOPERATIVE NONPROFIT MEMBERSHIP CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN.	)	DOCKET NO. E-01750A-11-0136

DIRECT

TESTIMONY

OF

MARGARET (TOBY) LITTLE

ELECTRIC ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 12, 2012

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EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01750A-11-0136

Margaret (Toby) Little's testimony makes recommendations regarding the Arizona Corporation Commission ("Commission" or "ACC") Utilities Division Staff's ("Staff") engineering evaluation of Mohave Electric Cooperative's ("MEC," "Mohave Electric" or "Cooperative") Application for a Determination of the Fair Value of its Property for Ratemaking Purposes, to Fix a Just and Reasonable Return Thereon and to Approve Rates Designed to Develop Such Return ("Application") filed with the Commission in Docket No. E-01750A-11-0136. In conjunction with Staff's engineering evaluation, Staff gives an account of its inspection of MEC's distribution system, of MEC's current operations and maintenance, and of MEC's future plans for its electric system. Staff has the following conclusions and recommendations:

1. It is Staff's conclusion that Mohave Electric:
    A. is operating and maintaining its electrical system properly,
    B. is carrying out system improvements, upgrades and new additions to meet the current and projected load of the Cooperative in an efficient and reliable manner. These improvements, system upgrades and new construction are reasonable and appropriate.
    C. has an acceptable level of system losses, consistent with the industry guidelines, and
    D. has a satisfactory record of service interruptions in the historic period from 2001 thru 2010, reflecting satisfactory quality of service.

2. Staff recommends that:
    A. Mohave Electric should continue with planned system improvements and additions as provided for in the 2008-2011 Construction Work Plan.
    B. Mohave Electric should continue with its plans in utilizing the SMART grid grant and with its REST plan.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Margaret (Toby) Little. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

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

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer.

Q. Please describe your educational background.

A. I received both my Bachelors and Masters Degrees in Electrical Engineering from New Mexico State University. I graduated with my Bachelors Degree in July 1972, and received my Masters Degree in January 1979. My Masters Program at New Mexico State University was in Electric Utility Management. I received my Professional Engineering ("P.E.") License in the state of California in 1980.

Q. Please describe your pertinent work experience.

A. I worked at the Arizona Corporation Commission from September 2010 to February 2011 as a Utilities Consultant, and since February 2011 I have been employed at the Commission as an Electric Utilities Engineer. During this time I have performed engineering analyses for financing cases, helped coordinate the Sixth Biennial Transmission Assessment, reviewed utilities' load curtailment plans and summer preparedness plans, and conducted various other engineering analyses. From 1983 through 1987 I was the Supervisor of System Planning for Anchorage Municipal Light and Power, the second largest utility in Alaska. There I had overall responsibility for distribution, transmission and resource planning for the utility and supervised six electrical engineers. From 1979 through 1982 and 1987 through 1988 I worked for R.W. Beck and Associates, a nationally recognized engineering firm. There I performed many types of engineering analyses involving resource and transmission planning and worked on the engineer's reports for the financing of a major generation facility in northern California. Prior to that, I worked in the System Planning Sections of San Diego Gas and Electric Company and Hawaiian Electric Company, where I had responsibility for short and long range distribution planning.

Q. As part of your assigned duties at the Commission, did you perform Staff's engineering analysis of the application that is the subject of this proceeding?

A. Yes, I did.

Q. Is your testimony herein based on that analysis?

A. Yes, it is.

PURPOSE OF TESTIMONY

Q. What is the purpose of your prefiled testimony?

A. The purpose of my testimony is to discuss Staff's engineering evaluation of the Mohave Electric Cooperative's ("MEC," "Mohave Electric" or "Cooperative") system operations and planning, and to present the results of this review. Mohave Electric's current rates and charges were approved by Commission Decision No. 57172 dated November 29, 2009.

ENGINEERING EVALUATION

Q. Did you perform an engineering evaluation of MEC's electrical system?

A. Yes, I did. In response to Mohave Electric's rate filing, I inspected the Cooperative's distribution system facilities on July 18 and 19, 2011, and discussed with MEC's officials certain elements of its rate filing and the Cooperative's Construction Work Plan ("CWP") 2008-2011. I also relied on the responses to Staff's data requests (both written and verbal) received from the Cooperative's officials.

Q. Will you please enumerate the highlights of your inspection of Mohave Electric's electric system?

A. Yes, I will. The following provides an account of my inspection of MEC's electrical system and my analysis of the data provided both in the initial filing and in response to data requests.

I visited the Cooperative's offices on July 18 and 19, 2011, and met with Ms. Peggy Gilman, Manager of Public Affairs and Energy Services, Mr. Arden Lauxman, Chief Financial Officer, and Mr. Neil Garney, Operations Supervisor. On July 18 we toured the western service area and I inspected various substations and distribution system elements; on July 19 we visited the eastern service area and I inspected various elements of that part of the electric system.

A. <u>Mohave Electric's Service Area</u>

The Cooperative has two separate service areas totalling nearly 1,300 square miles across three counties. The western service area is bordered on the west by the Colorado River, and roughly follows State Highway 95 from State Highway 68 in the north to Interstate 40 in the south and including Bullhead City. The eastern service area begins east of Kingman and follows State Road 93 south to the general area of Wikieup. It also follows Route 66 to the north into Coconino and Yavapai Counties. MEC serves the communities of Bullhead City, Fort Mohave, Mohave Valley and Golden Shores in the west and Wikieup, Hackberry and Peach Springs in the east. MEC's service territory includes very sparsely populated areas, rural communities and larger towns.

B. <u>Electric System Description</u>

MEC is a distribution cooperative providing electric service to its members. MEC has no generating capacity of its own and is a Partial Requirements Member of Arizona Electric Power Cooperative, Inc. ("AEPCO"). Power is delivered at Riviera, Topock, and Bullhead Substations to the western service territory and at Bill Williams, Kingman, and Round Valley Substations to the eastern service territory.

C. <u>Electric System Characteristics</u>

As of December 31, 2010, MEC provided electric power distribution service to 38,718 metered customers. Of these, 34,735 were residential customers, 23 were irrigation customers, 3,940 were Commercial and Industrial Customers 1000 kilo Volt Amperes ("kVA") or less, 3 were Commercial and Industrial Customers 1000 kVA or more, 16 were Public Street and Highway Lighting Customers, and one was a Sales for Resale Customer.

Mohave's system peak load increased from 148.7 Megawatts ("MW") in 2001 to 200.7 MW in 2010, showing an average annual increase of 3.89 percent over this time period. However, over the most recent five year period, (2005-2010), the average annual increase in peak load has been 0.87 percent, which Staff concludes is primarily due to poor economic conditions in the state as a whole and in particular the part of the state served by MEC.

The average number of services, including all classes of customers, increased from 30,830 in 2001 to 38,718 in 2010, indicating an average increase of 2.84 percent per year. The average annual growth in number of customers over the most recent five year period, (2005-2010), has been 1.01 percent, again reflecting the economic climate in the state. The peak load growth seems reasonable for the rural territory served by Mohave Electric.

MEC has 1,512 miles of energized lines, including 1,055 miles of overhead distribution lines[1], 349 miles of underground distribution cable[2] and 108 miles of sub-transmission lines[3]. The Cooperative's service territory is located within Western Area Power Administration's ("WAPA") Load Control Area[4].

D. <u>Annual System Losses</u>

Mohave Electric's annual historic system losses are listed below.

2005	4.08%
2006	4.05%
2007	4.16%
2008	4.92%
2009	4.55%
2010	3.03%

[1] 25 kV and below
[2] 25 kV and below
[3] 69 kV
[4] An electrical system bounded by interconnection metering and telemetry, capable of controlling generation to balance supply and demand, maintain interchange schedules with other control areas, and contribute to the frequency regulation of the interconnection.

These losses average 4.13 percent per year for the most recent six year period, (2005-2010), and are well below the reasonable limits in the guidelines provided by the American Public Power Association's Distribution System Loss Evaluation Manual applicable to electrical systems such as that of the Cooperative's. Typical distribution system loss values indicated in the said Manual range between 6 percent for urban systems to 10 percent for rural systems.

E. Quality Of Service

The outages that occur in a utility's system stem from a variety of causes and are an indicator of the quality of service to customers. Some of these causes are storm –related; others are relative to switching surges, equipment failure and planned outages. The historical data relative to Mohave's distribution system outages is shown in the following table.

Year	Avg. Customer Outage Hours per Year
2005	2.94
2006	6.94
2007	1.69
2008	2.43
2009	1.99
2010	2.34

The average over the past five year period for MEC has been 3.67 customer outage hours per year. According to the Rural Utilities Service ("RUS") Bulletin 161-5, average customer outage hours per year of five or under are acceptable. The information indicated in the above table shows that the Cooperative's service quality in terms of reliability exceeds the RUS standard. In answer to a question from Staff about the unusually high outage hours in 2006, MEC indicated that there was an especially severe monsoon storm in the summer of 2006 that caused the loss of both primary and back-up distribution feeds to several substations in the west service area. Crews were able to restore power in a reasonable time period given the extreme circumstances.

F. <u>Distribution System Inspection</u>

During my inspection of Mohave Electric's distribution system, it was noted that several system improvements and system upgrades had been made by the Cooperative in accordance with the Cooperative's Construction Work Plan 2008-2011. Several other upgrades and improvements listed in the CWP are planned to be constructed and placed in service in the near future.

In 2010, Mohave Electric completed the Natural Corrals Substation north of Wikieup in the east service area. This substation had been determined to be needed for voltage regulation at the south end of the service area. Voltage regulators in the area will remain as back-up in case of the loss of the substation. The new substation was inspected as part of the visit to the east service area.

MEC has completed upgrades to two distribution circuits, (Davis Circuit 1, (Phase I), completed in 2008; and Swam Circuit 3, completed in 2011), and one section of transmission, (Riviera to Lipan, completed in 2008) in the past few years to increase reliability and to meet additional demand. The current CWP provides for upgrading several other distribution circuits, (Hualapai Circuit 2, anticipated 2013; Hualapai Circuit 3, anticipated 2013; Davis Circuit 1, (Phase II), anticipated 2014;

Airport Circuit 1, anticipated 2014; WV Circuit 2, anticipated 2012; and Hualapai Circuit 2, anticipated 2012), also to increase reliability and to meet additional demand in the areas served by those feeders. In 2008 a second recloser was added at Davis Substation, creating Davis Circuit 2, and the transformer was upgraded at that substation, also in 2008.

In general, the MEC electric system appears to be well planned and maintained. No deficiencies or obvious problems were observed during the inspection tour. It was also noted that the substations are properly maintained, with safety-related equipment installed and 'Danger' signs installed on the fence around the substations. No oil leakage at the substation transformers was detected.

Mohave Electric has an ongoing plan to test wooden poles and replace those that have reached the end of their useful lives. According to MEC staff, the wooden poles in their service territory seem to have a longer than expected life span, perhaps due to the service territory's extremely dry climate.

Mohave has an aggressive plan for tree trimming; no areas needing trimming were observed on the inspection trip.

G. SMART Grid Grant And REST Plan

A SMART grid grant was received from United States Department of Energy ("DOE") in 2010. Mohave is a sub-grantee of DOE Grant Number DE-OE-0000451, under the Project Name of "Arizona Cooperative Grid Modernization Project ("ACGM")". The Prime Recipient in the grant is listed as Southwest Transmission Cooperative, Inc. ("SWTC"). Over the past year MEC has been installing SMART meters[5] and substation equipment using funds from the grant. Seventy one percent of the funds have been expended; ninety seven percent have been encumbered. Approximately forty percent of MEC customers presently have SMART meters installed.

MEC has also been pursuing an aggressive program of installing solar photovoltaic ("PV") panels on schools and public buildings in the service area over the past three years as approved in Mohave's Renewable Energy Standard and Tariff ("REST") Plans and using revenue from the required REST Tariff. MEC's renewable energy incentive program for residential and commercial members has experienced a level of incentives available under the REST budget that has been sufficient to meet the level of demand for the incentives. However, MEC recognizes the high number of low income and fixed income members in its service territory and has implemented the PV for Schools program and solar on other public buildings as a way for more members to benefit from the REST surcharge. The philosophy is to help all members as taxpayers by helping to lower the operating costs of government and schools.

These funds have been used to help pay for solar panel installation on City Hall and the Boys and Girls Club in Bullhead City, which provides cost-effective after school programs for working families, as well as local school buildings in Bullhead City, Fort Mohave, Mohave Valley and Topock. MEC anticipates that all schools in both the Bullhead City and Kingman service areas will have solar panels by the end of 2011. In addition, the local community college has installed 34 kW of solar panels, partially funded with the use of REST funds. MEC has

[5] The SMARTmeters installed on the MEC system do not transmit data using radio frequency; they transmit usage via hard-wire.

been instrumental in helping arrange Federal Department of Energy ARRA grants as well as private donations to supplement the REST funds for these installations.

H. Projected System Growth

MEC provided the following projections for system load growth over the next ten year period. The projections were taken from their 2010 Load Forecast Study and are based on assumptions and methodologies that include both historical weather data and projections for the economy over the next few years. The level of projected load growth seems reasonable for the service territory served by Mohave Electric.

Year	Projected System Peak Demand (MW)	Annual Projected Percent Growth
2011	203.9	1.6%
2012	206.8	1.4%
2013	212.9	2.9%
2014	218.6	2.7%
2015	224.4	2.7%
2016	230.4	2.7%
2017	236.5	2.6%
2018	242.9	2.7%
2019	249.4	2.7%
2020	256.0	2.6%

CONCLUSIONS AND RECOMMENDATIONS

Q. Based upon your testimony, what are Staff's conclusions and recommendations regarding the engineering evaluation of Mohave Electric's electrical system?

A. Staff's conclusions and recommendations are as follows:

1. It is Staff's conclusion that Mohave Electric:
   a. is operating and maintaining its electrical system properly,
   b. is carrying out system improvements, upgrades and new additions to meet the current and projected load of the Cooperative in an efficient and reliable manner. These improvements, system upgrades and new construction are reasonable and appropriate.
   c. has an acceptable level of system losses, consistent with the industry guidelines, and
   d. has a satisfactory record of service interruptions in the historic period from 2001 thru 2010, reflecting satisfactory quality of service.
2. Staff recommends that:
   a. Mohave Electric should continue with planned system improvements and additions as provided for in the 2008-2011 Construction Work Plan.
   b. Mohave Electric should continue with its plans in utilizing the SMART grid grant and with its REST plan.

Q. Does that conclude your testimony?

A. Yes, it does.