ORIGINAL

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BEFORE THE ARIZONA CORPORATION CO[MMISSION]

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 SURREBUTTAL TESTIMONY**

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission") hereby files the Surrebuttal Testimony of Staff witnesses Crystal S. Brown, Jerry E. Mendl, Candrea Allen and Bentley Erdwurm in the above-referenced matter. An unredacted (Confidential) version of Jerry Mendl's Exhibits (JEM-1, JEM-2 and JEM-5) have also been provided under seal to the Commissioners, their Policy Advisors and the assigned Administrative Law Judge.

RESPECTFULLY SUBMITTED this 13th day of March, 2012.

Bridget A. Humphrey

Bridget A. Humphrey, Staff Attorney
Brian E. Smith, Staff Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Original and thirteen (13) copies of the foregoing were filed this 13th day of March, 2012 with:

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

Copies of the foregoing were mailed
and/or emailed this 13th day of March, 2012 to:

Michael A. Curtis
William P. Sullivan
Melissa A. Parham
CURTIS, GOODWIN, SULLIVAN
UDALL & SCHWAB, P.L.C.
501 E. Thomas Rd.
Phoenix, Arizona 85012-3205
Attorneys for Mohave Electric
Cooperative, Inc.

Ashley Hodge

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

SURREBUTTAL

TESTIMONY

OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 13, 2012

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SCHEDULES

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

Staff's surrebuttal testimony recommends total annual revenues of $79,129,535 resulting in a $3,605,952 operating margin before interest on long-term debt or 7.50 percent rate of return on a $48,083,871 rate base. Staff's surrebuttal testimony responds to Mohave's rebuttal testimony on the following issues:

Operating Income:

a. Other Revenue
b. Rate Case Expense

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 in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Are you the same Crystal S. Brown who filed direct testimony in this case?

A. Yes.

PURPOSE OF SURREBUTTAL TESTIMONY

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

A. The purpose of my surrebuttal testimony in this proceeding is to respond, on behalf of Staff, to the rebuttal testimony of Mr. Michael W. Searcy who represents Mohave Electric Cooperative, Inc. ("Mohave" or "Cooperative").

Q. What issues will you address?

A. I will address the Other Revenue and Rate Case Expense issues that are discussed in the rebuttal testimony of Mohave's witness Mr. Michael W. Searcy. Staff witness, Mr. Jerry Mendl, will address the purchased power issue.

Q. What is Staff's recommended revenue?

A. Staff recommends total annual revenues of $79,129,535 resulting in a $3,605,952 operating margin before interest on long-term debt or 7.50 percent rate of return on a $48,083,871 rate base.

<u>OPERATING MARGIN</u>

Operating Margin – Other Revenue

Q. Has Staff reviewed the Cooperative's rebuttal testimony concerning Other Revenue?

A. Yes.

Q. Does Staff agree with the Cooperative?

A. Yes. In Staff's direct testimony, Staff increased Other Revenues by $55,820. The Cooperative has clarified, in its rebuttal testimony, that the $55,820 for revenues it anticipates receiving from a new deferred payment plan late fee was included in the Cooperative's direct testimony.

Q. Did the Cooperative make any other changes to its Other Revenue?

A. Yes. The Cooperative is increasing Other Revenues in its direct testimony by $3,735 to reflect service charge corrections.

Q. In recognition of the clarification and new information provided by the Cooperative in its rebuttal testimony, is Staff making any changes to its recommendation?

A. Yes. Staff's surrebuttal recommendation increases Other Revenues by $260,383, from $606,899 in its direct testimony to $919,367 in its surrebuttal as shown in surrebuttal Schedule CSB-3. Staff is removing its adjustment to reduce Other Revenues by $55,820 based on the clarification provided by the Cooperative and is reflecting $3,735 in additional revenue as calculated by the Cooperative in its rebuttal testimony.

Q. Is Staff's recommended $867,282 in Other Revenue the same amount as that proposed by the Cooperative in its rebuttal testimony?

A. Yes.

Q. How does Staff's recommended Other Revenue compare to the recommended Other Revenue in Staff's direct testimony?

A. Staff's recommended Other Revenues has decreased by $52,085, from $919,367 in its direct testimony to $867,282 in its surrebuttal testimony.

Operating Margin – Rate Case Expense

Q. Has Staff reviewed the Cooperative's rebuttal testimony concerning Rate Case Expense?

A. Yes.

Q. Does Staff agree with the Cooperative?

A. Yes. The Cooperative incurred costs to prepare and file a rate application using a 2009 test year. Additional costs were incurred to comply with Staff's request for a filing using 2010 data. Further, the Company has incurred costs due to Staff's prudence review of its purchased power costs. Moreover, the Cooperative's proposed four-year normalization period is appropriate because Staff is recommending that Mohave be ordered to file a new rate case no later than April 16, 2016. Therefore, Staff has included $100,000 in operating expenses to reflect $400,000 in rate case expense normalized using four years.

Q. What is Staff's surrebuttal recommendation?

A. Staff's surrebuttal recommendation increases revenues by $100,000 as shown in surrebuttal Schedule CSB-4.

Q. How does Staff's recommended Rate Case Expense compare to the recommended Rate Case Expense in Staff's direct testimony?

A. Staff's recommended Rate Case Expense has increased by $100,000, from $0 in its direct testimony to $100,000 in its surrebuttal testimony.

Q. Does this conclude Staff's surrebuttal testimony?

A. Yes, it does.

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

Surrebuttal Schedule CSB-1

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	$ 544,423
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	**$ 3,061,529**
6b	**Percent Increase (Line 6a / Line 7) - Per Staff**	N/A	**4.02%**
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	**$ 79,129,535**
9a	**Recommended Operating Margin Before Interest on L.T.-Debt**	$ 3,605,952	**$ 3,605,952**
9b	Recommended Operating Margin After Interest on L.T.-Debt	$ 1,285,224	$ 1,285,224
10a	**Recommended Operating TIER Before Intr on LT Debt(L4+L9a)/L4**	1.67	**1.67**
10b	Operating TIER After Interest on LT Debt(L4+L9b)/L4	1.59	1.59
11a	**Recommended DSC (L2+L3+L9a)/(L4+L5) - Per Staff**	N/A	**1.54**
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%	7.50%

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

Mohave Electric Cooperative, Inc.
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Test Year Ended December 31, 2009 (Updated to 2010)

Surrebuttal 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.
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Test Year Ended December 31, 2009 (Updated to 2010)

Surrebuttal Schedule CSB-3

OPERATING MARGIN - TEST YEAR AND STAFF RECOMMENDED

Line No.	DESCRIPTION	[A] COOPERATIVE TEST YEAR UPDATED TO 2010	ADJ NO.	[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	$ 2,801,146	$ 17,054,313
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	1	$ (594,737)	$ 61,207,940	$ -	$ 61,207,940
9							
10	Other Revenues	$ 606,899		$ -	$ 606,899	$ 260,383	$ 867,282
13	**Total Revenues (L1 + L8 + L10)**	**$ 76,068,006**		**$ 0**	**$ 76,068,006**	**$ 3,061,529**	**$ 79,129,535**
14							
15	EXPENSES:						
16	Purchased Power	$ 61,802,677	1	$ (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	2, 3	662,035	5,418,498	-	5,418,498
24	Depreciation and Amortization	2,239,666		-	2,239,666	-	2,239,666
25	Taxes	-		-	-	-	-
26	Total Operating Expenses	$ 75,456,285		$ 67,298	$ 75,523,583	$ -	$ 75,523,583
27							
28	Operating Margin Before Interest on L.T.- Debt	$ 611,721		$ (67,298)	$ 544,423	$ 3,061,529	$ 3,605,952
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)		$ (67,298)	$ (1,776,305)	$ 3,061,529	$ 1,285,224
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		$ (67,298)	$ 2,329,462	$ 3,061,529	$ 5,390,991
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.
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Test Year Ended December 31, 2009 (Updated to 2010)

Surrebuttal 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] ADJ #3 Rate Case Expense Ref: Sch CSB-7	[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	100,000	5,418,498
23	Depreciation and Amortization	2,239,666	-	-	-	2,239,666
24	Taxes	-	-	-	-	-
25	**Total Operating Expenses**	$ 75,456,285	$ (594,737)	$ 562,035	$ 100,000	$ 75,523,583
26						
27	**Operating Margin Before Interest on L.T.- Debt**	**$ 611,721**	**$ -**	**$ 32,702**	**$ (100,000)**	**$ 544,423**
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**	**$ (100,000)**	**$ (1,776,305)**
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	$ (100,000)	$ 2,329,462

Mohave Electric Cooperative, Inc. | **Surrebuttal 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]

Mohave Electric Cooperative, Inc.
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Surrebuttal Schedule CSB-6

OPERATING MARGIN ADJUSTMENT NO. 2 - ADMINISTRATIVE AND GENERAL REVENUE & EXPENSE

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COOPERATIVE AS FILED Suppl Sch A1.0	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Administrative and General	$ 4,756,463	-	$ 4,756,463
2	To Reclassify In House Labor & Benefits	-	120,042	120,042
3	To Reclassify Legal Services	-	335,233	335,233
4	To Remove Lobbying Costs	-	-	-
5	To Remove Costs to Prepare Fuel Bank Reports	-	23,015	23,015
6	To Reclassify Consulting Costs	-	83,745	83,745
7	To Remove Unsupported Costs	-	-	-
8	Total Administrative and General	$ 4,756,463	562,035	$ 5,318,498
9				
10				
11				
12		[D]	[E]	[F]
13		Reclassified From Purchased Power Expense		
14-16		Per Staff From Sch CSB-5	Amount Disallowed	Amount Reclassified
17	To Remove In House Labor & Benefits	$ 120,042	$ 0	$ 120,042
18	To Remove Legal Services	335,233	(0)	335,233
19	To Remove Lobbying Costs	32,038	(32,038)	-
20	To Remove Costs to Prepare Fuel Bank Reports	23,015	0	23,015
21	To Remove Consulting Costs	83,745	-	83,745
22	To Remove Unsupported Costs	664	(664)	-
23		$ 594,737	$ (32,702)	$ 562,035

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

Mohave Electric Cooperative, Inc.
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Surrebuttal Schedule CSB-7

OPERATING INCOME ADJUSTMENT NO. 3 - RATE CASE EXPENSE

		[A]	[B]	[C]
LINE NO.	**Description**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Rate Case Expense	$ -	$ 100,000	$ 100,000

References:

Column A: Company Schedule C-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

SURREBUTTAL

TESTIMONY

OF

JERRY MENDL

ON BEHALF OF COMMISSION STAFF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 13, 2012

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EXHIBITS

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

This surrebuttal testimony responds to the rebuttal testimony of MEC witnesses Carlson, Stover and Searcy. It also responds to additional information that MEC has provided since the filing of Staff direct testimony to document the purchased power costs in incurred from August 2001 through December 2006.

As a result of this additional documentation, Staff was able to refine and reduce the amounts of the adjustments Staff recommended to the purchased power bank balance. Ratepayers would still receive credits, but less credits than it would have been before MEC supplied additional documentation supporting its purchased power costs for 2001-2006.

Nothing in MEC's rebuttal testimony or in the information MEC provided resulted in any changes to Staff's recommendations regarding the purchased power base cost which was based on a 2010 test year.

Following is a summary of the recommendations Staff made in its direct testimony as supplemented or modified in this surrebuttal testimony. 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. In addition, direct MEC to provide an assessment supporting its decision to keep or modify its current criterion, and to clarify how binding the criterion will be on MEC resource planners.

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 shall include only the actual costs of purchased power and associated transmission and reject MEC's unilateral attempt to include ineligible costs.

5. Adopt Staff's specification of cost components which may be included in the fuel and purchased power cost adjustor. The specified cost components shall be limited to RUS Accounts 555, 565, and 447 for purchased power and 501 and 547 if MEC purchases fuel for power generation in the future. These are the same components specified by the Commission in 2005 for AEPCO.

6. Remove $594,737 from the 2010 test year base cost of power 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, lobbying costs and legal costs associated with planning and procurement of purchased

power. Reallocate $562,035 of those costs to revenue requirements for the general rates.

7. Reduce MEC's purchased power bank balance (credit to ratepayers) by $594,737 to adjust for the inclusion of these ineligible costs as soon as practical after the Commission issues its order in this docket.

8. Reduce MEC's purchased power bank balance (credit to ratepayers) by $91,537 to adjust for MEC's errors and omissions in calculating the purchased power cost and bank balance between August 2001 and December 2010, inclusive.

9. Determine that the actual eligible purchased power costs were adequately documented from August 2001 through December 2010.

10. Determine that MEC's actual purchased power costs, adjusted to remove the ineligible costs and errors and omissions, are prudent and reasonable for August 2001 through December 2010.

11. Require MEC to file a rate case with purchased power prudence review no later than September 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 to ensure the purchased power cost data and supporting information remain fresh. The prudence review will cover the period beginning January 2011and ending in December of the test year. MEC may file sooner if necessary, with a test year ending no more than 8 months prior to the filing date.

12. Require MEC to adjust the bank balance in the next prudence review to remove in-house labor costs, consulting costs, lobbying costs and legal costs associated with planning and procurement of purchased power that MEC included in its purchased power adjustor in 2011 and 2012. Although identified as ineligible costs in this rate case (prudence review through 2010), the costs will actually have occurred in the next prudence review period and the adjustments shall be made in that review.

13. 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.

14. Require MEC and Staff to meet within two months of this order to discuss options for streamlining the rate case process. Also identify issues and information required for the next case, leaving the flexibility to modify the issues as the case approaches.

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

16. 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.

17. Acknowledge that MEC's selection and management of Western Area Power Administration ("Western") to provide critical services are prudent and reasonable.

18. 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.

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

INTRODUCTION

Q. Are you the same Jerry E. Mendl who filed direct testimony in this docket on January 12, 2012?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond on behalf of Utilities Division Staff ("Staff") to the rebuttal testimony submitted by Mr. Carlson, Mr. Stover and Mr. Searcy. I am responding to the following subjects raised in the rebuttal testimony, many of which were addressed by more than one of Mohave Electric Cooperative's ("MECs") witnesses:

1. Adjustment of purchased power bank balance for undocumented 2008 power costs;
2. Adjustment of purchased power bank balance for undocumented 2001-2006 power costs;
3. Adjustment of purchased power bank balance and base rate for ineligible expenses;
4. Application of margins on third party power sales to reduce purchase power costs charged under Purchase Power Cost Adjustor ("PPCA");
5. Reconsideration of limits on spot market purchases;
6. Future case filing schedules and content; and
7. Other issues.

SECTION 1: UNDOCUMENTED 2008 POWER COSTS

Q. Are you still recommending that the Arizona Corporation Commission ("Commission") disallow MEC's undocumented claim of purchased power expenses of $163,221.69 in 2008 and credit the ratepayers by reducing the bank balance by that amount?

A. No.

Q. Why not?

A. After Staff filed testimony on January 12, MEC provided additional information. MEC provided documentation adequately supporting those claimed expenses on January 20, 2012, in its Supplemental Response to JEM-9.14. The issue and adjustment are moot as a result.

RECOMMENDATIONS

Q. What is your recommendation?

A. I recommend that the Commission determine that the actual eligible purchased power costs were adequately documented in 2007, 2008, 2009 and 2010.

SECTION 2: UNDOCUMENTED 2001-2006 POWER COSTS

Q. Are you still recommending that the Commission 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 credit ratepayers by reducing the bank balance by that amount?

A. No.

Q. Why not?

A. MEC has since provided most of the missing documentation.

In a February 17, 2012 meeting with Staff, MEC agreed to provide the missing documentation for 2001 through 2006. The missing documentation involved both the expenses that flow into the purchased power adjustor and the credits that offset some of those costs in the adjustor. Based on MEC's initial responses to JEM-13.1 and JEM-13.2, Staff was able to identify claimed expenses of $47,603,244.39 for which Staff had no documentation in the August 2001 through December 2006 period. In addition, Staff identified $9,556,853.76 of credits for which Staff had no documentation in that period.

Through several supplemental responses to JEM-13.1, MEC was able to provide documentation for additional claimed costs and credits. As of March 7, 2012, MEC had provided documentation adequately supporting all but $134,933.00 of claimed expenses for the August 2001 through December 2006 period, and all but $769,026.98 of credits applied to the calculation of the purchased power adjustor during that period. The remaining undocumented expenses consist of $134,933.00 of power MEC purchased from Aggregated Energy Services ("AES") in July 2002. Undocumented credits in the amount of $768,708.00 are the result of power MEC sold to AES in August – December 2002. MEC indicates that no documentation of the AES expenses and credits is available from 2002 because, at that time, AES members did not exchange invoices. The remaining undocumented credit is for $318.96 from Citizens Utilities in April 2004. MEC believes it was misfiled but cannot justify searching further for it. See Surrebuttal Exhibit JEM-6.

On March 12, 2012, MEC provided secondary documentation of the volumes of power purchased from and sold to AES in July through December 2002. These were derived from the amount of energy dispatched monthly from resources available to MEC and the monthly amount sold to serve native load, multiplied by the average rates then in effect. These derived values, while not matching the FA-1 reports precisely, provide sufficient documentation to support the recorded costs and credits. The remaining amounts are negligible.

Based on the documentation for most costs and credits MEC provided since Staff filed its direct testimony, Staff is no longer recommending the $1.946 million prudence adjustment. Because the remaining undocumented amounts are negligible, Staff is recommending no prudence adjustment for undocumented costs and credits.

Staff believes that MEC has made a good faith effort, though belatedly, to provide this documentation. However, Staff believes that the documentation supporting costs and credits used in the calculation of the purchased power adjustor and purchased power bank balance should be maintained and accurate. It should not have taken this much time and effort to verify calculations MEC must have performed to prepare its FA-1 reports. Staff believes this problem will be mitigated or eliminated in the future by its recommendation that no more than five years elapse between MEC's rate cases.

Q. Does Staff's elimination of the $1.946 million prudence adjustment render the arguments made in rebuttal testimony of MEC's witnesses moot?

A. Yes, although one deserves some attention. MEC witnesses Carlson and Stover contest my statement regarding the missing documentation of costs and credits for 2001-2006, specifically that "it is likely that the requisite information is no longer available." Mendl Public Direct, page 26, lines 13-14. Both witnesses Carlson and Stover argue that my claim that the information is likely to not be available is unsubstantiated and led to the wrongful application of the prudence adjustment. They in fact suggested that Staff was at fault for not having compelled them to provide the information after they refused to provide it.

My observation that the information was quite likely not available was based on MEC's own statement in its September 8, 2011 letter from Mr. Sullivan objecting to Staff Data Request Set 3 requesting information back to 2001. Mr. Sullivan stated:

> Importantly, not only do these requests seek a large amount of detailed information involving periods well outside of the test year ending December 31, 2009 that would be extremely burdensome *if not impossible to gather*, the Commission's Decision No. 72055, dated January 6, 2011 renders the bulk of the information of limited or no value in accessing Mohave's current and future power purchasing practices. (Emphasis added)

Since MEC understood that Staff was performing a prudence review, and since it is in the Company's self interest to provide all documentation supporting the costs subject to the performance review, I concluded that MEC's objection to providing the requested information was most likely because significant portions of it were "impossible to gather." Given the risk of disallowance of expenses that MEC did not document, I reasonably believed MEC would not withhold information that it possessed.

My belief that MEC would not withhold documentation of costs was ultimately proved wrong, and in the time since Staff filed testimony proposing the prudence adjustment, MEC was able to provide much of the needed documentation. However, MEC also proved my statement that it is likely that the "requisite information is no longer available" to be correct in that MEC could only produce derived approximate secondary documentation for over $900,000 of costs and credits.

Q. Does the documentation that MEC has now provided address the infrastructure, organization and policy/practices that MEC had in place between 2001 and 2010?

A. No. The information provided was documentation of the costs. It did not address whether MEC had an appropriate power procurement process, including MEC's organization and power planning and procurement approaches, prior to 2010. Staff's recommendation that the Commission determine that it is inconclusive whether MEC's policies of power supply planning and implementation prior to 2010 are reasonable and appropriate.

Q. Does the fact that MEC has now provided the documentation needed to support its costs for 2001-2006 mean that those costs are prudent?

A. No. It simply means that the costs were verified to exist. It does not mean that they are prudent or that they should be recovered through the purchased power adjustor mechanism.

Q. What additional analyses did you perform for the 2001-2006 purchased power costs?

A. I examined the data for ineligible costs. I also compared the purchase power prices to the market prices and checked for errors or omissions in the calculation of the purchased power costs and bank.

INELIGIBLE COSTS

Q. Did you find any ineligible costs that MEC included in the August 2001 through December 2006 purchase power cost adjustor and bank mechanism?

A. No. All of the costs in that time period appear to be direct costs of power purchases or sales) and their associated transmission. MEC did not attempt to incorporate legal and consulting costs, lobbying costs, or in-house staffing costs as it did in 2010.

COMPARISON TO MARKET POWER PRICES

Q. How did MEC's average purchase power costs compare to market prices in the August 2001-December 2006 period?

A. MEC's average purchased power costs excluding transmission compared favorably with market prices. Surrebuttal Exhibit JEM-1 CONFIDENTIAL, page 1, compares the MEC average cost excluding transmission to the monthly Mead market price. The shaded band represents the range between monthly off-peak and on-peak prices at Mead. MEC's average monthly purchased power cost could be expected to fall within or below the band. Generally, it does.

Surrebuttal Exhibit JEM-1 CONFIDENTIAL, page 1, is an update of Exhibit JEM-15 CONFIDENTIAL, page 1. Both cover the entire January 2001 through December 2010 period. MEC's average costs differ slightly in Surrebuttal Exhibit JEM-1 CONFIDENTIAL because these are based on the final actual fuel costs provided by MEC for 2001-2006 in response to JEM-13.1 and JEM-13.2. MEC's average costs as displayed in Exhibit JEM-15 CONFIDENTIAL, page 1, were based on unverified Staff information for 2001-2006.

Q. How did MEC's costs for block power purchases compare to market prices in the August 2001-December 2006 period?

A. Three of the four block purchase prices were in line with market prices. The fourth, which was in effect from 2001 through early 2003, was between two and three times the Mead market prices and MEC's average price. Please refer to Surrebuttal Exhibit JEM-1 CONFIDENTIAL, page 2.

Q. Why were the prices of the fourth block power purchase so high when compared to the market prices?

A. As I previously discussed in my direct testimony, there could be several reasons. First, the contract was likely negotiated at a time that the market prices were much higher. Surrebuttal Exhibit JEM-1 CONFIDENTIAL, page 1 shows that market prices in the first quarter of 2001 were above the price of the expensive block purchase which was in effect by August 2001. If market prices had not tumbled, the block power purchase would have appeared quite economic.

Second, the contract is a demand and energy type contract. The demand charges represent roughly half of the monthly cost, except in the final months of the contract. The demand charges then were about 80% of the monthly cost. The energy charge was slightly above the Mead market price, meaning that any discretionary take of power under this contract would be small. This block purchase ended up taking on the character of a capacity supply rather than an energy supply. Dividing a fixed demand cost by fewer kWh increases the average rate for the block purchase. Since the average rate of the block purchase is presented in Surrebuttal Exhibit JEM-1 CONFIDENTIAL, page 2, it is not surprising that it is much higher, especially for the months late in the contract. If Mead market prices had not fallen so much after the contract was negotiated, it is possible that more energy would have been taken under the contract, substantially reducing its average price per kWh.

Q. Did MEC act imprudently when purchasing this block power contract?

A. No. Due to these factors, although the average cost of that block purchase is substantially above market prices, I cannot conclude that MEC acted imprudently in obtaining that power given the nature of the market prices while it was being negotiated and subsequent falling of market prices.

In any event, this contract supplied less than 0.1 percent of the energy required by MEC. It would have little effect on the overall cost or rates.

ERRORS IN THE CALCULATION OF THE PURCHASE POWER COST

Q. Did you identify any errors in the calculation of the purchased power costs included in the purchased power adjustor and bank?

A. Yes. The errors and omission resulted in the over-collection of purchased power costs from MEC's ratepayers through the purchased power adjustor mechanism in the amount of $91,537.43.

Q. Please describe the error that you found.

A. The error is that MEC overstated the impact of the load control adjustment when calculating the amount of the purchased power cost that should be allocated to its ratepayers.

MEC's calculation of actual purchased power costs consists of adding all of its purchased power costs, and then subtracting the costs of supplying special contracts and third party sales to arrive at the net cost of purchased power for those customers subject to the purchased power adjustor rate. MEC calculates the cost of supplying special contracts and third party sales by applying the applicable rates for power from AEPCO to the volumes it sells to special contracts and third parties. In most months, the cost of power to supply a special contract is simply the volume multiplied by AEPCO's Commission-approved flat energy rate. The cost to supply the special contract is subtracted from the overall cost, leaving the rest to be recovered from ratepayers. The higher the cost to serve the special contract, the less of the total cost is borne by other ratepayers.

One special contract contains a load control provision. When that provision is exercised, it reduces the cost of serving the special contract load because AEPCO provides a credit on its billing to MEC. Thus MEC's overall actual costs decrease. MEC made an error in its calculation of the load control billing credit, overstating the actual credit. By overstating the actual load control credit and applying that calculated load control credit to the cost of serving the special contract, MEC shifted costs to its ratepayers subject to the purchase power adjustor.

Q. How were the costs shifted to MEC's ratepayers?

A. The shift occurred because MEC's ratepayers pay the remainder of the actual purchased power costs after having subtracted the cost of serving the special contract's loads. By overstating the amount of load control credit generated by the special contract customer, MEC understates the actual cost of serving the special contract customer. Because customers subject to the purchased power adjustor pay the remainder of the actual total purchased power cost, understating the cost of serving the special contract will overstate the cost of serving everyone else.

Q. How did you calculate the costs of this error?

A. MEC's spreadsheets show the calculation of the load control credit which then goes on to reduce the apparent cost of serving the special contract. The load control adjustment was applied in 11 months during the time period August 2001 through December 2010. I looked up the AEPCO billing to MEC for each of those eleven months to determine the actual load control credit received by MEC. The difference over all eleven months was

$90,166.38 over-billed to the ratepayers subject to the purchase power cost adjustor. Please refer to Surrebuttal Exhibit JEM-2 CONFIDENTIAL.

Q. Where did the extra money collected from MEC's ratepayers go?

A. It should have ended up in the members' patronage capital credit account. By understating the actual cost of serving the special contract, MEC would overstate the apparent margin on its special contract sales. The margins should flow to the members' patronage capital credit account. The higher calculated margins would be generated by increased costs borne by all ratepayers subject to higher rates under purchased power adjustor mechanism.

This is another reason that margins on sales to entities not subject to the purchased power cost adjustor mechanism should offset the purchased power costs, as I recommended in my direct testimony.

Q. Did MEC make any other errors in the calculation of the purchased power costs included in the purchased power adjustor and bank?

A. Yes. In the documentation supplied by MEC in response to JEM-13.1, MEC used $5,958.58 and $4,943.78 of power for self use in July and September 2003, respectively. The corresponding values used in the spreadsheets to calculate the actual purchased power costs were $4,584.48 and $4,949.78. The cost of power for self use is not included in the actual costs included in the purchased power adjustor and bank. It is subtracted from the total cost of power purchased, like the power purchased to serve special contracts. Thus understating the self use increases the cost to MEC's ratepayers subject to the PPCA.

MEC's documentation shows that MEC understated the cost of self-use power in July 2003 by $1,374.10 and overstated the cost of self-use power in September 2003 by $6.00. The net impact of the self-use errors is an adjustment to credit the purchased power bank by $1,368.10.

Q. Are you recommending any other adjustment to the costs in the 2001-2006 time frame?

A. Yes. In January 2005, AEPCO corrected an error on its December 2004 bill to MEC. The correction was a credit plus the interest. MEC recorded only the correction in its calculation of the actual cost and bank balance. It should have also included the interest. Correcting that omission would reduce ratepayer purchased power costs by $2.95. Although this amount is insignificant, the concept is not.

Q. Please summarize your recommended adjustments for errors and omissions?

A. The Commission should adjust the purchased power bank balance to credit MEC's customers in the following amounts:

Load Control Error	$90,166.38
Self-use Error	$1,368.10
Interest Omission	$2.95
Total Errors and Omission Adjustment	$91,537.43

RECOMMENDATIONS

Q. What are your recommendations?

A. Staff recommends that the Commission:

1. Determine that it remains inconclusive whether MEC's policies of power supply planning and implementation as they existed from August 2001 through December 2009 were appropriate and reasonable.
2. Determine that MEC's actual purchased power costs are now adequately documented beginning in August 2001 through 2006.
3. Reduce MEC's purchased power bank balance by $91,537.43 to adjust for calculation errors and omissions.
4. Determine that MEC's remaining actual purchased power costs for the period August 2001 through 2006 are prudent and reasonable.

SECTION 3: INELIGIBLE EXPENSES

Q. In your direct public testimony, page 17 line 12, you indicated that Staff was not able to reach a conclusion whether MEC included ineligible costs in its purchased power adjustor during the August 2001 through December 2006 time frame. In light of the documentation provided by MEC since February 28, 2012, have you determined whether MEC included ineligible costs in 2001-2006?

A. Yes. Staff has now concluded that MEC did not include any ineligible expenses among the costs used to calculate the purchased power adjustor and bank balance for 2001-2006.

Q. Mr. Stover argues (rebuttal, page 17) that the ineligible costs should be included because they meet two criteria that you set forth in your direct testimony. Is this a compelling argument?

A. No. My testimony stated "As a ratemaking principle, fuel and purchased power clauses are reserved for volatile price changes that are outside the control of the regulated utility." Mr. Stover transformed that straightforward statement into two criteria, namely that any costs within the control of the utility should be recovered through general rates and any volatile costs can be include in an adjustor. My statement was clearly predicated on fuel and purchased power costs as an overriding criterion. In-house staff costs, legal fees and consulting services are not fuel and purchased power costs, even if they might be related to purchased power. MEC is requesting the Commission to step onto a slippery slope. If in-house staff costs associated with managing and recording power purchases are part of the purchased power adjustor, what would differentiate them from the in-house staff needed to evaluate system alternatives (to conduct long range planning activities)? Or from the secretarial/administrative staff used to prepare letters, invoices, and make payments? Or from the resources needed to prepare bills to retail customers to recover the costs of the purchased power? The overarching requirement that a cost be included in the purchased power adjustor is that it is for purchased power and associated transmission. The costs that I identified as ineligible do not meet that overarching criterion – they are not purchased power costs.

Q. Has the Commission previously addressed what costs could be included in a fuel and purchased power cost adjustor for a cooperative?

A. Yes. The Commission addressed that issue in an AEPCO application for a rate increase in 2004. By Decision No. 68071, the Commission adopted Staff's specification of cost components that could be included in a fuel and purchased power cost adjustor. AEPCO concurred with Staff's specification. MEC was a party to the case.

Q. What cost components did Staff specify would be included in the adjustor in the AEPCO rate case.

A. Staff specified that:

> The cost components would be the costs recorded in RUS Accounts 501 (fuel cost for steam power generation, less legal fees, less fixed fuel costs except for gas reservation), 547 (fuel costs for other power generation), 555 (purchased power costs, both demand and energy), and 565 (wheeling costs, both firm and non-firm). The prudent direct costs of contracts used for hedging fuel and purchased power costs may also be included. Power supply costs directly assignable to special contract customers would not be included in the calculation. Non-Class A sales for resale (RUS Account 447), less revenue for legal expenses, would be credited against the cost components. Direct Testimony of Barbara Keene, Docket No.E-01773A-04-0528, page 3).

Excerpts from Ms. Keene's testimony are attached as Surrebuttal Exhibit JEM-3.

Q. Is the same specification of cost components appropriate and applicable for MEC?

A. Yes. At this time, MEC would use only Accounts 555 and 565 and 447 as appropriate. I have attached the RUS definition of those accounts in Surrebuttal Exhibit JEM-4.

MEC currently owns no generation and thus would have nothing to include for fuel costs in Accounts 501 and 547. MEC does evaluate the option of owning generation as part of its planning process. It is possible that MEC will own generation capacity in the future, at which point all the cost components would be utilized.

The Commission should direct MEC to base its purchased power cost adjustor (and the fuel and purchase power cost adjustor if that becomes applicable to MEC in the future) on the same cost components the Commission previously specified for AEPCO.

Q. Mr. Carlson states his understanding "that had these costs not been collected through our PPCA, Mohave's financial performance would have been adversely affected." (Rebuttal, page 13, line2) What is your perspective on this point?

A. Mr. Carlson effectively admitted to developing a new revenue stream which raises rates without Commission approval. Here is why.

Until 2010, MEC indeed had not collected those costs through their PPCA. Prior to 2010, these ineligible costs were being incurred by MEC but recovered through the general rates. In 2010, apparently as the Company's financial performance was becoming challenged, MEC segregated out these ineligible costs and included them in the PPCA – an action Mr. Carlson states was needed to avoid adversely impacting financial performance.

MEC created a new revenue stream to collect the ineligible costs through the PPCA mechanism, but did not correspondingly reduce the revenue stream from general rates that had provided recovery for the ineligible costs. When MEC talks about recovering these ineligible costs through the PPCA, what it is really doing is doubling up on its recovery, since from August 2001 through December 2009 (at least) these costs were being recovered exclusively through the general rates.

If MEC's point was to simply reclassify the ineligible expenses to roll them into the PPCA, it would have removed them from the general rate classification when MEC moved them to the PPCA. In fact, MEC increased the revenue stream by unbundling legal, consulting and in-house staff costs and rebundling some of them with purchased power and recovering costs in both places.

Q. Mr. Stover testifies that if the Staff proposal regarding ineligible costs is adopted, that the ineligible costs MEC recovered through the PPCA in 2010, 2011 and until the effective date of the order in 2012 "should not be included in the prudence adjustment because this would result in refund to the consumers of costs that the Commission has determined to be recoverable." (Rebuttal page 18, line 31) Do you agree?

A. No. I would agree if MEC had reduced its general rates when it segregated out the ineligible costs for inclusion in the PPCA. But it did not. Thus while the Commission would determine that all of the ineligible costs, except the lobbying costs, would be recoverable, they would have been recovered through the base rates. Thus the ineligible costs included in the PPCA in 2010 should be disallowed in the current rate case by adjusting the purchased power bank. Including lobbying costs, the entire $594,737 should be removed from the purchased power bank effective right after the order is issued.

The 2011 and partial 2012 ineligible costs will also have been collected in the general rates as well as through the PPCA. Staff's recommendation in my direct testimony was that the Commission "direct MEC to adjust that bank balance for any ineligible costs that may have been recovered through the purchased power adjustor after December 31, 2010." (Mendl Public Direct testimony, page 46. line 22) The amount of the adjustment will not be known until after MEC ceases its current practice of including ineligible costs in the PPCA, which will be as of the effective date of the order in the current case. Staff did not specify a date by which that adjustment would be made; however, the reasonableness and prudence of MEC's purchased power costs would normally be part of the prudence review in the next rate case. As a result, the purchased power bank should be adjusted to disallow whatever ineligible costs MEC has recorded in its PPCA during the next prudence review. If the Commission adopts Staff's recommendation, that prudence adjustment would be made in the case filed in 2016. This will spread the adjustment over two dates five years apart, thereby mitigating the financial impact on MEC.

Finally, the 2010 test year serves as the base for forward looking rates. As such, the entire $594,737 of ineligible expenses from 2010 should be removed from the PPCA test year. The ineligible expenses, except for lobbying, would be included in the general rates, set in such a way to recover all costs other than purchased power while providing adequate financial coverage.

RECOMMENDATIONS

Q. What are your recommendations?

A. Staff recommends that the Commission:

1. Disallow $594,737 of ineligible expenses from 2010 from the purchased power bank balance effective as soon as practical after the Commission issues the order in the current docket.
2. Disallow the ineligible expenses from 2011 and 2012 collected through the PPCA as soon as practical after the Commission issues the order in the next rate case (filed in 2016).
3. Remove the ineligible expenses from the 2010 test year PPCA and include the recoverable costs in the general rate (i.e., include $562,035, all but the lobbying costs, in the general rates).
4. Adopt Staff's specification of the cost components that MEC may include in the purchased power adjustor.

SECTION 4: THIRD PARTY POWER SALES

Q. Do you agree with Mr. Stover's conclusions regarding the two alternatives for allocating the margins from third party sales?

A. No. Mr. Stover reasonably describes the alternatives and even their respective benefits. However, he reaches the conclusion that it is more equitable and preferable to flow the margins on the sales to net income. Staff believes it is preferable to flow the margins on third party sales to offset purchased power costs to reduce the PPCA rate and/or reduce the purchased power bank balance (credit the ratepayers).

Q. What advantages does Mr. Stover cite for flowing the margins to net income?

A. Mr. Stover cites the benefits under MEC's method as resulting in higher coverage ratios, increasing the equity ratio for MEC and increasing the equity of each member in the Cooperative (Rebuttal page 24, line 8).

Q. Do you agree that these alleged benefits warrant rejecting Staff's proposal to flow the margins to offset purchased power costs?

A. No. Each of the benefits cited by Mr. Stover comes at a cost – namely that the Cooperative has more money which comes at the expense of its customers. This is not "free money" that will increase the coverage ratios and equity. It is money that would have otherwise been used to offset ratepayer costs which the ratepayer now must involuntarily "invest" in the Cooperative.

Staff's proposal results in the economic benefits associated with the margin on a third party sale flowing back to customers on a timelier basis. It is not clear when a customer would actually receive a tangible benefit under MEC's proposal. It could be many years or even decades before MEC's capital needs developed such that customers could derive a tangible benefit. That creates intergenerational equity problems for MEC's proposed approach.

Q. Does Mr. Stover also cite inequities as a reason to adopt MEC's approach?

A. Yes. Mr. Stover argues that inequities result under Staff's proposal because the sales occur during low load conditions, and thus would get credited back to customers using power during low load conditions although a large part of MEC's fixed costs are paid during peak periods. (Rebuttal Page 24, line 28)

The fallacy in Mr. Stover's argument is that the customer's rates do not change monthly. They may change periodically if the purchased power bank balance gets excessive. MEC can set its PPCA rates taking into account the size of the bank balance. The bank balance acts as a buffer essentially eliminating Mr. Stover's alleged timing inequities. Nonetheless, Staff's approach will certainly flow the benefit to ratepayers much more quickly that MEC's proposal.

RECOMMENDATIONS

Q. What are your recommendations?

A. Staff recommends that the Commission adopt Staff's proposal to use the margins from third party sales to offset purchased power costs.

SECTION 5: LIMITS ON SPOT MARKET PURCHASES

Q. Mr. Stover rejects your recommendation that MEC reconsider the arbitrary limit on the amount of spot market power MEC will consider for meeting loads. What is your reaction?

A. Mr. Stover misses the point and clouds the issue by drawing a distinction between a policy and a criterion, and also by introducing an argument that MEC can always offset power from AEPCO if the spot market price is lower.

I referred to it as a policy while Mr. Stover indicated that it is not a policy but a planning criterion which Mohave can change at any time. (Rebuttal page 27, line 9) That distinction is a red herring. The persons in charge of planning are not in a position to change either a criterion or a policy, either will have the same effect. Power supplies relying on more than the small arbitrary limit imposed by the criterion will not be considered. And that may result in increased costs.

Mr. Stover argues that if spot prices are low, MEC can always back down on power taken from AEPCO. The problem with that is that Mr. Stover mixes economy energy with capacity planning. Backing down AEPCO generation if the spot market is cheaper is a classic economy energy approach, minimizing the real time cost of energy (utilizing a set of capacity resources acquired based on long term capacity planning).

However, the criterion in question is for capacity planning, not for economy energy as Mr. Stover suggests. After MEC determines its load forecast, it has several alternatives available to provide the capacity needed to serve the projected loads. The capacity need can be met by AEPCO, block purchases and the spot market. Since the amount of capacity available from AEPCO is fixed, if the reliance on the spot market is arbitrarily limited, that forces MEC's planners to secure block power. A review of Surrebuttal Exhibit JEM-1 CONFIDENTIAL (page 2) and Exhibit JEM-15 CONFIDENTIAL (page 4) shows that from August 2001 through December 2010, the block power contracts were typically higher priced than the spot market. The point is that the criterion setting an arbitrary limit on spot market supplies is related to fulfilling capacity requirements. The reason for the criterion is to ensure that there is not excess risk that spot market prices will increase and cause increases in the cost of service. I would agree with Mr. Stover that spot prices could be higher or lower than block power prices. However, as spot market prices have stabilized, it would be inappropriate to prevent the utilization of spot market resources because of a criterion designed when spot market prices were volatile.

Mr. Stover suggested that AEPCO generation could be curtailed if spot market prices ended up lower than AEPCO production costs. This is not related to capacity or capacity planning. It is economy energy that is dispatched day of or day ahead. It substitutes cheaper spot market power for more expensive power from existing capacity resources. Economic dispatch requires that the market power prices are checked many times daily to determine if an opportunity exists to lower the production cost. The criterion does not apply to this situation. Again, it is a capacity planning rather than an economy energy criterion.

Mr. Stover obfuscates the point by mixing the capacity planning criterion with economy energy dispatch.

Q. Is there any downside to raising the criterion to allow more capacity needs to be served by spot market resources?

A. No. Raising the small arbitrary limit does not require MEC's planners to rely more heavily on the spot market to determine their capacity resources. It only gives them the opportunity to consider more spot market capacity if conditions warrant that. By leaving the limit at its present low level, that forces planners to plan for block power purchases instead of spot market supplies.

RECOMMENDATIONS

Q. What are your recommendations?

A. Staff recommends that the Commission adopt Staff's proposal that MEC reconsider the arbitrary limit on spot market supplies for capacity planning. The Commission should require MEC to provide an assessment supporting its decision to keep or modify its current criterion, and to clarify how binding the criterion will be on MEC resource planners.

SECTION 6: FUTURE CASE FILING SCHEDULES AND CONTENT

Q. Mr. Carlson and Mr. Searcy both address Staff's recommendation that the Commission require MEC to file its next rate case by April 1, 2016. Is Staff open to modifying its recommendation?

A. Yes. Staff believes Mr. Searcy makes a valid point in waiting until September 1 in order to get an audited report and would support that modification.

Mr. Carlson offers to meet with Staff to develop a streamlined reporting and review process. That would be reasonable, as long as the necessary information is generated and decisions made regarding prudence, future test year, and other issues. Staff's observation is that this process was unnecessarily prolonged because of difficulties acquiring data. This may have been the result of differing opinions about the purpose of this case. It would go a long way to streamline the case by determining in advance what will be the purpose of the case, including, for example:

- Conduct a prudence review
- Specify the time period
- Set future general rates
- Set future base purchase power cost
- Reconcile, adjust or settle the purchase power bank

Q. Could scheduling the next rate case to occur within five years of the last case simplify and streamline the process?

A. Yes. Having a more frequent rate case would reduce the large volumes of data that had to be reviewed in this docket. By looking at only 5 years rather than 10, it would simplify the review. It would also make it easier to recall or reconstruct the context in which MEC made its power purchases.

If rates are more frequently adjusted, the odds of there being a financial emergency before MEC comes in for a rate case are reduced. If problems with the cost recovery, rate structures, power supply costs, volatile markets, and other things arise, they can be resolved on a more-frequent schedule. If conditions occur that require urgent attention, MEC could file the next rate case less than five years after the last rate case. Under Staff's proposal, the next case would be filed in 2016, but could be filed sooner if needed as long as the test year ends no more than 8 months prior to the filing date.

RECOMMENDATIONS

Q. What are your recommendations?

A. Staff recommends that the Commission:

1. Adopt Staff's modified proposal that MEC file its next rate case on September 1, 2016.
2. Direct Staff and MEC to meet within two months of the order in this case to discuss options for streamlining the rate case process.
3. Identify the nature of the issues and information required for the next case, leaving flexibility to modify the issues as the rate case approaches.

SECTION 7: OTHER ISSUES

Q. Beginning on page 19 of his rebuttal testimony, Mr. Stover discusses the financial implications to MEC resulting from Staff's proposed adjustments to the purchased power bank. Are Mr. Stover's calculations applicable?

A. No. Mr. Stover bases his calculation on a Staff adjustment of $3.1 million. The correct Staff adjustment at this time is $0.7 million, less than one-fourth of the amount used be Mr. Stover. That would dramatically change his calculations.

Q. Please explain.

A. Mr. Stover estimated the total Staff adjustment to be $3,102,802. (Stover rebuttal, page 20, line 11) This consists of adjustments of $1,946,000 for the 2001-2006 prudence penalty, of $594,737 for the 2010 ineligible costs, and of $562,065 (or more) for ineligible costs incurred after 2010. He assumed that the adjustment for ineligible costs incurred after 2010 would be made coincident with all of the adjustments made for costs incurred in the current prudence review period (August 2001 through December 2010).

The current adjustments are much less than what he used. Staff's current adjustments are $91,537 for calculation errors and omissions, and $594,737 for the 2010 ineligible costs. The correct Staff adjustment for this case is $686,274.

The Staff adjustment for ineligible costs included in the PPCA in 2011 and 2012 would not actually occur until all of the purchased power costs were reviewed in the next rate case. Since MEC continues to book ineligible costs for recovery through the PPCA until the order in this case is effective, the final amount is not known at this time. However, as suggested by Mr. Stover, the amount is likely to be similar to the amount MEC incurred in 2010, on the order of $600,000.

Q. **Mr. Carlson testified that "increases are sought only when they are necessary to continue to provide reliable electric service, both in the short term and the long term, and/or in order to satisfy financial criteria established by their lenders." (Page 5, line 31) Is this principle borne out by MEC's PPCA and purchased power bank?**

A. No, it does not appear to be. I looked at the long term history of MECs PPCA rate versus the average monthly cost. From 2001 to 2006, the rate stayed the same while the average cost was cyclical. The bank balance was correspondingly cyclical near zero. When monthly costs started rising, MEC was slow to adjust its rates, meaning that the bank balance became strongly under-collected, where it remained from roughly June 2006 through December 2008. In 2008, MEC finally substantially raised the PPCA rates and by mid-2009, MEC's bank balance moved into an over-collection mode. It remained in a strong over-collection mode throughout 2010. While MEC dropped its PPCA rates a little, the level of over-collection persisted. So it does not appear that increases are only sought when necessary in that MEC allowed substantial swings in the purchased power bank balance in recent years. Please refer to Surrebuttal Exhibit JEM-5CONFIDENTIAL.

SUMMARY OF STAFF'S RECOMMENDATIONS

Q. Please summarize your recommendations from your Direct Testimony of January 12, 2012 as modified by your Surrebuttal testimony.

A. The following is a list of recommendations made in my Public Direct Testimony, beginning on page 46, as modified to reflect changes resulting from additional information filed by MEC since I filed direct testimony and in response to MEC's rebuttal testimony.

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. In addition, direct MEC to provide an assessment supporting its decision to keep or modify its current criterion, and to clarify how binding the criterion will be on MEC resource planners.

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 shall include only the actual costs of purchased power and associated transmission and reject MEC's unilateral attempt to include ineligible costs.

5. Adopt Staff's specification of cost components which may be included in the fuel and purchased power cost adjustor. The specified cost components shall be limited to RUS Accounts 555, 565, and 447 for purchased power and 501 and 547 if MEC purchases fuel for power generation in the future. These are the same components specified by the Commission in 2005 for AEPCO.

6. Remove $594,737 from the 2010 test year base cost of power 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, lobbying costs and legal costs associated with planning and procurement of purchased power. Reallocate $562,035 of those costs to revenue requirements for the general rates.

7. Reduce MEC's purchased power bank balance (credit to ratepayers) by $594,737 to adjust for the inclusion of these ineligible costs as soon as practical after the Commission issues its order in this docket.

8. Reduce MEC's purchased power bank balance (credit to ratepayers) by $91,537 to adjust for MEC's errors and omissions in calculating the purchased power cost and bank balance between August 2001 and December 2010, inclusive.

9. Determine that the actual eligible purchased power costs were adequately documented from August 2001 through December 2010.

10. Determine that MEC's actual purchased power costs, adjusted to remove the ineligible costs and errors and omissions, are prudent and reasonable for August 2001 through December 2010.

11. Require MEC to file a rate case with purchased power prudence review no later than September 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 to ensure the purchased power cost data and supporting information remain fresh. The prudence review will cover the period beginning January 2011and ending in December of the test year. MEC may file sooner if necessary, with a test year ending no more than 8 months prior to the filing date.

12. Require MEC to adjust the bank balance in the next prudence review to remove in-house labor costs, consulting costs, lobbying costs and legal costs associated with planning and procurement of purchased power that MEC included in its purchased power adjustor in 2011 and 2012. Although identified as ineligible costs in this rate case (prudence review through 2010), the costs will actually have occurred in the next prudence review period and the adjustments shall be made in that review.

13. 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.

14. Require MEC and Staff to meet within two months of this order to discuss options for streamlining the rate case process. Also identify issues and information required for the next case, leaving the flexibility to modify the issues as the case approaches.

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

16. 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.

17. Acknowledge that MEC's selection and management of Western Area Power Administration ("Western") to provide critical services are prudent and reasonable.

18. 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.

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

Q. Does this complete your surrebuttal testimony?

A. Yes.

SURREBUTTAL EXHIBIT JEM-1

CONFIDENTIAL

SURREBUTTAL EXHIBIT JEM-2

CONFIDENTIAL

Q. What cost components would be included in the adjustor?

A. The cost components would be the costs recorded in RUS Accounts 501 (fuel costs for steam power generation, less legal fees, less fixed fuel costs except for gas reservation), 547 (fuel costs for other power generation), 555 (purchased power costs, both demand and energy), and 565 (wheeling costs, both firm and non-firm). The prudent direct costs of contracts used for hedging fuel and purchased power costs may also be included. Power supply costs directly assignable to special contract customers would not be included in the calculation. Non-Class A sales for resale (RUS Account 447), less revenue for legal expenses, would be credited against the cost components.

Q. How does Staff's proposal differ from AEPCO's proposal regarding the components in the adjustor?

A. Staff proposes to include gas reservation charges, demand charges for purchased power, firm wheeling costs, and non-energy charge revenue from non-Class A sales for resale that AEPCO did not propose to be included in the adjustor.

Q. Why is Staff proposing that those items be included?

A. Gas reservation charges should be included because they are a part of the cost of obtaining natural gas for operating power plants.

Demand charges for purchased power should be included so that the method of cost recovery does not influence decision making when negotiating contracts. Some contracts in the marketplace are structured with only a per kWh energy charge that would include capacity costs. Other contracts are structured so that capacity costs are recovered through a per kW demand charge. AEPCO should negotiate these contracts so that they obtain the best deal for ratepayers. If only energy charges went into the adjustor, the method of cost recovery could influence the resulting structure of the contracts.

Firm wheeling costs should be included in the adjustor because they should be considered when negotiating purchased power and wheeling contracts. If only non-firm wheeling costs were included in the adjustor, the method of cost recovery could influence the type of contract that AEPCO would negotiate.

Including all revenue from non-Class A sales for resale as an offset to costs allows the Class A members to benefit from the margins of those sales. Since Class A members pay for the costs of the resources, it only seems fair that they benefit from the non-Class A sales.

Q. How often would the adjustor rate be reset?

A. The adjustor rate, initially set at zero, would be reset semi-annually on October 1, 2006, and April 1, 2007, and thereafter on October 1 and April 1 of each subsequent year. AEPCO would submit a publicly available report, with a revised tariff, that shows the calculation of the new rate on September 1, 2006, and March 1, 2007, and thereafter on September 1 and March 1 of each subsequent year. The adjustor rate would become effective with billings for October and April unless suspended by the Commission.

Q. Are the above dates different from those proposed by AEPCO?

A. Yes. Staff changed the dates to have the new rates go into effect before the winter season and before the summer season, taking into account the probable time for a Commission decision in this case.

Q. Would there be a balancing account?

A. Yes. The dollars associated with the calculation of the adjustor rate would be accumulated in a balancing account.

RUS Account Definitions

555 Purchased Power

A. This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall also include, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, and spinning reserve capacity. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, or capacity. Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.

B. The records supporting this account shall show, by months, the demands and demand charges, kilowatt-hours and prices thereof under each purchase contract and the charges and credits under each exchange or power pooling contract.

Note: The records supporting this account shall provide information pertaining to the purchase of power from renewable energy sources.

565 Transmission of Electricity by Others

This account shall include amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others.

447 Sales for Resale

A. This account shall include the net billing for electricity supplied to other electric utilities or to public authorities for resale purposes.

Note: Revenues from electricity supplied to other utilities for use by them and not for distribution, shall be included in Account 442, Commercial and Industrial Sales, unless supplied under the same contracts as and not readily separable from revenues includible in this account.

B. Account 447 shall be subaccounted as follows:

447.1 Sales for Resale—RUS Borrowers

447.2 Sales for Resale—Other

447.1 Sales for Resale—RUS Borrowers

A. This account shall include the net billing for electricity supplied to RUS borrowers for resale.

B. Records shall be maintained so as to show the quantity of electricity sold and the revenue received from each customer.

Note: Revenues from electricity supplied to other utilities for use by them and not for distribution, shall be included in Account 442, Commercial and Industrial Sales, unless supplied under the same contract as and not readily separable from revenues includible in this account.

447.2 Sales for Resale—Other

A. This account shall include the net billing for electricity supplied for resale to utilities not financed by RUS.

B. Records shall be maintained so as to show the quantity of electricity sold and the revenue received from each customer.

Note: Revenues from electricity supplied to other utilities for use by them and not for distribution, shall be included in Account 442, Commercial and Industrial Sales, unless supplied under the same contract as and not readily separable from revenues includible in this account.

SURREBUTTAL EXHIBIT JEM-5

CONFIDENTIAL

Jerry Mendl

From: Pierce, Dorothy [dorothy.pierce@chguernsey.com]
Sent: Wednesday, March 07, 2012 4:10 PM
To: Jerry Mendl
Cc: William Sullivan; Candrea Allen; Bridget Humphrey; Michael Curtis
Subject: Missing invoices 2001 - 2006

Jerry,

We know your time is short and Mohave and I have located all documents you have requested for the entire 9 ½ year period involved in your audit of Mohave's power purchases with the exception of:

- 6 AES transactions in 2002 (involving July 2002 purchases of $134,475 and credits over the months of August through December 2002 of $964,961 – resulting in a net credit to the fuel bank balance of $830,486);
    - On June 3, 2005, Commission Staff was advised that during the first six months of operations AES members did not exchange invoices. See, JEM 13.1, 2002 Confidential, page 36 of 51. These are the same months for which you are requesting documentation.
- a $318.96 credit to the fuel bank balance in April of 2004.
    - While the statement is likely misfiled and locatable eventually, we cannot justify searching further for this single invoice.

Thank you for working with Mohave and me on this effort.

Dorothy

Dorothy Pierce
Senior Consultant

C. H. GUERNSEY & COMPANY
Engineers • Architects • Consultants

5555 North Grand Boulevard
Oklahoma City, OK 73112-5507
405.416.8131 Direct
405.620.4818 Cell
405.416.8111 Fax
dorothy.pierce@chguernsey.com
http://www.chguernsey.com

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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

SURREBUTTAL

TESTIMONY

OF

CANDREA ALLEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 13, 2012

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

Staff's surrebuttal testimony contains recommendations regarding Mohave Electric Cooperative, Inc.'s ("Mohave") line extension policy and prepaid metering.

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. Have you previously filed testimony in this docket?

A. Yes.

Q. As part of your employment responsibilities, were you assigned to review Mohave Electric Cooperative, Inc.'s ("Mohave") rebuttal testimony?

A. Yes. I have reviewed the rebuttal testimony of Michael Searcy on behalf of Mohave concerning Staff's recommendations regarding Mohave's proposed line extension policy and prepaid metering.

Q. Does Staff agree with Mohave's alternative regarding its proposal to include no more than fifty percent (50%) of the cost of the transformer as part of its line extension allowance amount for individuals not within a subdivision?

A. No. Staff continues to recommend that Mohave not charge for the cost of a transformer as part of its line extension allowance amount for individuals not within a subdivision. Please refer to Staff's direct testimony filed January 12, 2012. In addition, in the on-going

Navopache Electric Cooperative, Inc. rate proceeding. Staff has also recommended that the cost of a transformer not be included as part of the line extension allowance for individual customers. Please refer to the direct testimony of Richard Lloyd filed February 1, 2012, in Docket No. E-01787A-11-0186.

Further, Staff continues to believe 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.

Q. Does Staff agree with Mohave's proposal to include prepaid metering service as part of its Service Rules and Regulations?

A. Staff continues to believe that Mohave should further investigate and evaluate its proposal for prepaid metering service and file, in a separate docket, an application for Commission approval. However, in the alternative, should the Commission determine that Mohave's proposal is appropriate at this time; Staff recommends that Mohave's prepaid metering option be approved with the following conditions:

- Mohave participate in stakeholder meetings in an effort to improve its prepaid metering service specifically for its income restricted customers;
- Mohave file a request for the appropriate waivers of the Commission's Rules including but not limited to disconnection and metering. However, disconnection waivers should not be waived with respect to extreme weather events (refer to A.A.C. R14-2-201.46) or conditions and customers specified under A.A.C. R14-2-211.A.5 and for those customers under appropriate circumstances but beyond the scope of A.A.C. R14-2-211.A.5;
- Mohave file for Staff review of its proposed Prepaid Metering Agreement, and any promotional/advertising material to be used, prior to implementation;
- Mohave develop for Staff review, prior to implementation, information to be given to potential prepaid metering customers that provides information detailing the classes of customers who qualify for prepaid metering, the customers for

whom prepaid metering is reasonable and appropriate, and the rules and requirements of the prepaid metering option (to be provided prior to signing the proposed Prepaid Metering Agreement). This recommended documentation should be signed and/or initialed and dated as being read and understood by the customer prior to the Prepaid Metering Agreement being signed by the customer.

- Mohave be required to file a prepaid metering tariff that includes the daily rates for the charges specified in the proposed Standard Offer Residential Service Tariff;

- Mohave be required to file, as a compliance item, a revised RES Tariff that includes a section for prepaid metering customers that indicates the daily REST surcharge that would be charged. The method for calculating the daily REST surcharge for prepaid metering customers should be the REST monthly maximum approved by the Commission divided by 30 days; and

- Mohave be required to file, in this docket, an annual report with the following information:

    - The number of prepaid metering customers per month;

    - The number of disconnects per account per month, specifying the number of low-income disconnections;

    - The number of prepaid metering customers that have been disconnected for 24 hours or more (in 24 hour increments) and the number of accounts with repeated disconnections; and

    - A summary of any unforeseen issues that could impact the implementation of or the future progress of the prepaid metering option and recommendations on ways to improve these potential issues.

    - The number of customer complaints specific to prepaid metering

In addition, Staff believes that the following language should be removed from Mohave's proposed Prepaid Metering Agreement:

> Electric service is subject to immediate disconnection any time an account does not have a credit (prepaid) balance, even if the customer has submitted medical documentation that termination would be especially dangerous to a permanent resident of the premises or where life supporting equipment dependent on utility service is in use.

Staff believes that this language is inconsistent with the Commission Rules regarding termination of service. Further, Staff believes that Mohave's proposed Prepaid Metering Agreement specify those customers in which Staff has recommended disconnection waivers not be granted.

Staff notes that Exhibit 2 of Tyler Carlson's rebuttal testimony is unclear and appears to be inconsistent with Mohave's proposed Subsection 102-I.1.e. This section indicates that if a prepaid metering customer fails to make a payment and the account is disconnected, the customer can make a payment, including the applicable Reconnection/Establishment Fee. However, the proposed Prepaid Metering Agreement indicates that only a $20.00 minimum is required. Staff believes that Mohave should clarify the exact charges prepaid metering customers would pay in order to reconnect an account in both its Prepaid Metering Agreement and its Service Rules and Regulations.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. 1. Staff continues to recommend 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 Staff's direct testimony.

2. Staff continues to recommend that Mohave file, in a separate docket, an application for Commission approval of prepaid metering, no later than 120 days after a Decision in this matter, as discussed in Staff's direct testimony. However, should the Commission approve Mohave's proposed prepaid metering service, Staff recommends the conditions specified above be included.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
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Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF MOHAVE ELECTRIC COOPERATIVE, INC., 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

SURREBUTAL

TESTIMONY

OF

BENTLEY ERDWURM

CONSULTANT

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 13, 2012

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SCHEDULES

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

This surrebuttal testimony addresses issues related to cost allocation and rate design for Mohave Electric Cooperative ("Mohave") that were addressed by Mohave's witness, Mr. Michael W. Searcy, in his rebuttal testimony. Staff recommends the following:

- The standard residential customer charge should be set at $13.50 per month.
- The peak period recommendations for residential time-of-use as presented in Mr. Searcy's rebuttal testimony and the winter peak definition from Mr. Searcy's direct testimony should be approved.
- Mohave's proposed inverted blocking structure for residential time of use should be approved, subject to the condition that the cents per kWh block differential matches the block differential approved for the regular residential rate.
- There should be a $5.00 differential between the customer charges of the standard residential rate and the residential time-of-use rates.
- The existing Large Commercial and Industrial Time-of-Use rate schedule should be frozen for new customers. The frozen rate should be eliminated in Mohave's next general rate case.

INTRODUCTION

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

A. My name is Bentley Erdwurm. I am a Consultant employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Did you also prepare pre-filed direct testimony in this proceeding on behalf of the Commission Staff?

A. Yes.

Q. What is the scope of this testimony?

A. I will address issues related to cost allocation and rate design for Mohave Electric Cooperative ("Mohave") that were addressed by Mohave's witness, Mr. Michael W. Searcy, in his rebuttal testimony. Areas that I address include (1) residential rate design (the residential customer charge and inclining block rate structure), (2) the residential time-of-use ("TOU") rate design, (3) customer charges applicable to other sub-classes of customers that are tied to the residential and residential time-of-use customer charges, and (4) the design of the Large Commercial and Industrial Time-of-Use ("LC&I TOU") rate.

RESIDENTIAL RATE DESIGN

Q. Please discuss your recommendations related to the residential customer charge and residential rate design, detailing how they compare to Mr. Searcy's recommendations and to your recommendations in direct testimony.

A. Staff modifies its recommendation for the standard residential customer charge, increasing the Staff-proposed charge to $13.50 per month, as opposed to the $12.00 charge recommended in my direct testimony. Mr. Searcy proposed a $16.50 charge in his direct testimony, and has recommended an escalating charge in his rebuttal testimony. Mr. Searcy's rebuttal proposal escalates the customer charge from an initial $12.00 (to match the recommendation from Staff's direct testimony) to $16.50 by November 2014. The current residential customer charge is $9.50 per month. Staff does not support the phase-in of a residential customer charge in excess of $13.50 in advance of Mohave's next general rate case. A phase-in rate would be administratively burdensome, and Mohave would be required to provide notice to its customers for each rate adjustment. Moreover, phase-in of increased customer charges would require simultaneous decreases in kWh (energy) charges to conform to the approved revenue target, unless Mohave would opt to accept the lower kWh charges from the point of rate implementation.

Staff maintains its direct testimony recommendation for an inclining block rate design with a 1.5 cent (15 mills) escalation in the price per kWh between the rate blocks, and Mr. Searcy indicates in his rebuttal testimony that the 15 mill block differential is acceptable to Mohave. The inclining block structure, characterized by unit prices rising with usage levels, helps mitigate bill impacts for customers with "basic needs" usage levels and encourages the prudent and economic use of scarce resources.

Mr. Searcy implies that Staff's residential customer charge recommendation in direct testimony was driven solely by bill impact considerations and that Staff seeks to modify the cost of service study to justify the customer charge recommendation (Searcy Rebuttal, page 16 line 37 through page 17 line 4). On the contrary, Staff's customer charge recommendation was driven by a costing methodology restricting the customer-related classification to metering, meter-reading, the service drop, billing and customer service. Customer impact may place an upper limit on customer charge increases.

Q. Why is Staff now recommending a higher residential customer charge of $13.50, as opposed to the $12.00 supported in direct testimony?

A. Staff believes that a $13.50 monthly residential customer charge - while in excess of the levels associated with metering, meter-reading, the service drop, billing and customer service - is reasonable given Mohave's acceptance of the inclining rate structure with a 15 mill block differential. In effect, the customer charge and the block structure are a "package deal." Additionally, Mr. Searcy has described how a less dense system (typically a more rural service territory) must install poles, wire and transformers that may serve only a few customers, and that some minimum size of poles and wire and transformer must be used. This is a valid observation when customers are in isolated areas. Mr. Searcy explains why he believes that a customer component related to poles, wires and transformers is necessary for this less dense system. Staff believes that *for some utilities*, circumstances may justify *some* customer component for poles, lines and transformers in its cost study; however, the magnitude of the customer component for these items has not been supported for Mohave in this proceeding. Even in rural systems, not all customers are isolated, and the rationale for a customer-related classification for poles, lines and transformers may be non-existent for these customers. To the extent that the number of customers in dense areas is higher than the number of customers in isolated areas, the magnitude of the customer-related component for poles, lines and transformers will be reduced or eliminated. Are isolated customers the exception or the rule on the Mohave system? More study is required.

Given that higher customer charges may have adverse bill impacts on bills for "basic needs" levels, and may be contrary to providing incentives supporting the prudent use of energy, Staff contends that the default position in future Mohave rate cases should be that no portion of poles, lines and transformers is classified as customer-related without some study supporting the magnitude of customer component.

Mr. Searcy has noted in his direct testimony and Staff here acknowledges that Decision No. 71230 included language that customer service costs include "the customer component of distribution line expense, a portion of transformer expense, [in addition to] the meter, service drop expense and meter reading and customer records expenses." However, Decision No. 71230 applied to Trico, not to Mohave and not to other utilities. Staff contends that the aforementioned "customer component of distribution line expense" is for many utility systems – especially denser systems - more phantom than substance. Staff notes that utilities - both those with more dense territories and those with less dense territories - typically view rate stability as desirable, that higher residential customer charges typically promote rate stability, and that higher residential customer charges may be supported, rightly or wrongly, through classifying as customer-related a portion of poles, lines and transformers. Any use of a customer classification for poles, lines and transformers must be justified, and regardless of the results of the cost study, the Commission is not compelled to base any specific class rate design solely on the cost study. Staff's direct testimony discusses other criteria that can influence rate design.

Mohave is characterizing the implementation of a residential customer charge less that $16.50 as placing it at risk for not recovering fixed costs. Clearly, revenue stability is enhanced when customer charges are used to collect a larger percentage of revenue (assuming the typical situation where the number of customers varies less than demand or energy billing determinants). However, just as Mohave contends that customer charge levels should not be driven predominately by customer impact considerations; Staff contends that these charges should not be driven predominately by revenue stability considerations.

RESIDENTIAL TIME-OF-USE

Q. Please discuss your residential time-of-use recommendations.

A. The residential time-of use rate design involves several issues where Staff's and Mohave's recommendations differed in direct testimony. The key issue for Staff raised in direct testimony was the length of the summer peak period. Specifically, Staff recommended that the summer peak period contain fewer hours than proposed by Mohave in direct testimony. Mr. Searcy in his rebuttal testimony modified his summer peak hour definition to be closer to Staff's recommendation. This resolution now allows Staff to recommend acceptance of other residential time-of-use rate features proposed by Mohave, including the specifics of the inclining rate structure and the customer charge differential relative to the standard residential time-of-use rate.

Q. Please discuss the length of the summer peak period in the residential time-of-use rate.

A. The Staff recommended in its direct testimony that the number of peak hours in Mohave's residential time-of-use rate be reduced. Typically, shorter peak periods are more effective at controlling coincident peak demand spikes in Arizona's desert climate.

Additionally, Mohave has proposed two residential time-of-use options: one option (Option 1; peak on weekdays only) restricts peak hours to weekdays (Monday-Friday) only, and the other (Option 2; peak applies to weekdays and weekends) includes both weekday and weekend peak hours. Customers would be able to choose which time-of-use option they want. Staff in direct testimony supported the use of the same peak hours in both options, with the rates differentiated by pricing. Mohave supported a shorter peak period for the weekend option so that they could publicize the weekend option as having the same number of peak hours in the week. Mohave believes that customers would be more accepting of the Option 2 rate (peak applies to weekdays and weekends) if the number of peak hours under Option 2 does not exceed the Option 1 rate (where peak applies to weekdays only). That is, customers may focus more on the peak period definition than on pricing details. Staff agrees that this is a reasonable argument and recommends that the Commission approve differing peak periods for Options 1 and 2 as recommended in Mr. Searcy's rebuttal testimony.

For Mohave's proposed Residential time-of-use Option 1 (peak on weekdays only), Mohave in direct testimony designated the summer (April 16-October 15) peak period as 12:00 p.m. (noon) to 9:00 p.m. (9 hours). Under proposed Option 2, (peak applies weekdays and weekends), Mohave in direct testimony designated the summer peak period as 2:00 p.m. to 8:30 p.m. (6.5 hours). Staff in its direct testimony recommended that the summer peak period for both options end at 7:30 p.m., and that it begin no earlier than 1:00 p.m. for either option. Either 1:00 p.m. or 2:00 p.m. is an appropriate summer peak start time under either option. Staff's primary aim in direct testimony was to reduce the length of the summer peak period.

Mr. Searcy in rebuttal for Mohave presented a compromise position that shortened the summer peak period for both residential time-of-use Options 1 and 2. Mohave's revised proposal for Residential time-of-use Option 1 (peak on weekdays only) designates the summer (April 16-October 15) peak period as 12:00 p.m. (noon) to 7:30 p.m. (7.5 hours). Revised proposed Option 2, (peak applies weekdays and weekends), designates the summer peak period as 2:00 p.m. to 7:30 p.m. (5.5 hours) (Searcy rebuttal testimony page

24, lines 21-29). The shorter peak periods are appropriate and Staff supports Commission approval of Mohave's peak period recommendations as presented in Mr. Searcy's rebuttal testimony. Mohave's proposed winter peak definition from Mr. Searcy's direct testimony is acceptable to Staff.

Q. Please discuss the inclining block rate structure in the residential time-of-use rate.

A. In direct testimony, Mohave recommended an inclining block structure allowing more TOTAL kWh in the lower (and less expensive) blocks than the level of kWh allowed in lower blocks in the regular residential rates. Staff in direct testimony recommended an "adder" of "x cents" per kWh applicable to the first 400 kWh of monthly usage (which first-block adder would result on a credit per kWh for the 1st 400 kWh of monthly usage), an adder of "x+$0.015" per kWh for the next 600 kWh, and an adder of "x+$0.030" per kWh for the consumption in excess of 1000 kWh (which third-block adder would result on a credit per kWh for the 1st 400 kWh of monthly usage). Staff's design from direct testimony best mimics the inclining block mechanism of the regular residential rate in that a time-of use customer buys the same number of kWh in a block as a regular residential customer. In contrast, Mohave's proposed inverted block structure offers first block pricing for both the first 400 kWh of monthly on-peak kWh and for the first 400 kWh of monthly off-peak kWh. As such, a customer could purchase more than 400 kWh of total (peak and off-peak combined) first block (lower priced) kWh. Mohave's proposal to offer more lower-priced, lower-block kWh to time-of-use residential customers makes time-of-use more attractive to potential subscribers, especially higher-use customers who otherwise would purchase a significant portion of energy in the more expensive third block of the regular (non-time-of-use) residential rate. The appeal of the time-of-use rate to higher-use customers is further enhanced because these customers have more end-uses (e.g., pool pumping or significant air conditioning use) that can be curtailed in whole or in part, and more potential for load shifting. Providing incentives for high-use customers to move load away from peak periods benefits all customers on the system.

Staff realizes that Mohave's proposed blocking mechanism is simpler and easier to explain to customers than the blocking mechanism presented in the Staff direct testimony. Staff is persuaded that Mohave's position on the inclining block mechanism is preferred to Staff's direct testimony position on residential time-of use blocking. Mohave's blocking design makes the residential time-of-use program more attractive to potential subscribers, and will promote subscription of a program that benefits all customers by reducing energy use at peak times. Staff recommends approval of Mohave's inverted blocking structure subject to the condition that the cents per kWh block differential will match the block differential approved for the regular residential rate (which under Staff's proposal is 15 mills per kWh (1.5 cents per kWh) between adjacent blocks, for a total differential of 3.0 cents per kWh).

Q. Please discuss Mohave's proposed $5.00 differential between the customer charge in the standard residential rate and the customer charge in the residential time-of-use rate.

A. Staff recommended in direct testimony that the customer charge differential be set at $3.00 (i.e., the time-of-use customer charge exceeds the regular residential customer charge by $3.00). However, further review of differential in the costs of specific meters used by Mohave ($125 for the standard residential meter vs. $449 for the meter for time-of-use installations) plus Mohave's documentation of additional costs related to time-of-use for customer service, installation, meter reading, billing and accounting indicates that the $5.00 differential is cost-justified. In conjunction with other promotional features of the time of use program (such as availability of two residential time-of-use options and time-of use customers' ability to purchase more lower block, less expensive energy), Staff is satisfied that subscription to and acceptance of the time-of-use program should not be adversely affected by the larger $5.00 differential. Therefore Staff recommends approval of a $5.00 differential between the customer charges of the standard residential rate and the residential time-of-use rates.

LARGE COMMERCIAL AND INDUSTRIAL TIME-OF-USE RATE DESIGN

Q. Please discuss your recommendation for the Large Commercial and Industrial Time-of-Use ("LC"& "I TOU") rate.

A. During the test-year, the existing LC&I TOU rate served three customers around 565,000 kWh. To put this in perspective, a large residential customer averaging 3,000 kWh per month would use 36,000 kWh in a year, and the annual consumption of the three LC&I TOU customers would equate in usage to only 16 of the large residential customers. Viewed another way, LC&I TOU revenue in the test year was less than one part out of a thousand in Mohave system revenue. Finally, the three test-year LC&I TOU customers have significantly different load profiles than typical Large Commercial and Industrial customers on the Mohave system.

As explained in Staff direct testimony, Mohave's proposed revision to the LC&I TOU rate as presented in Mr. Searcy's direct testimony is well-reasoned and cost-based. The Mohave proposal here is a huge improvement over the existing design of the LC&I TOU rate. Under the existing design, LC&I TOU customers can avoid contributing for capacity-related facilities by controlling their peak demand (highest kW) during the on-peak period. While shifting load from on-peak periods to off-peak periods provides benefits to the system, off-peak users must still contribute for downstream costs that their off-peak load helps create. Otherwise, the off-peak user "free rides" on the system and other customers must pick up costs created by the free rider.

Moving from the existing LC&I TOU rate to Mohave's proposed LC&I TOU would result in a bill increase of over 40% to existing LC&I TOU customers. Staff in direct testimony focused on mitigating this percentage increase, and recommended an LC&I TOU rate with an on-peak demand charge of $11.11 per kW-month, substantially lower than Mohave's proposed $23.00 per kW-month. This change reduced the percentage increase to the three existing LC&I TOU customers to around 27%.

In retrospect, the substantial reduction in the on-peak demand charge will mean that subscribers to LC&I TOU will pay too little for service relative to other customers, which is unfair to the other customers. If such a non-compensatory LC&I TOU rate were approved and implemented, substantial LC&I load could migrate to the time-of-use option, and more customers and larger loads would seek to have the windfall grandfathered for as long as possible. Initially, Mohave could suffer substantial margin losses, and over the longer run (after Mohave's next rate case) other customers could be burdened with the costs imposed by LC&I TOU customers because of the potential the windfall could be grandfathered.

Staff believes a simple and fair solution is to grandfather the three existing LC&I TOU customers (customers must be on the rate as of March 1, 2012) onto a frozen LC&I TOU(F) rate with the $11.11 on-peak demand charge (the Staff direct LC&I TOU rate conformed to a minor system revenue change), as shown in Exhibit DBE-3. Staff proposes that the frozen rate be eliminated in Mohave's next general rate case. The three customers on the frozen rate would then need to choose between the regular LC&I rate and the LC&I TOU rate (the rate generally available).

Staff opposes Mohave's recommendation in rebuttal to phase-in higher on-peak demand charges for the three existing LC&I customers. The impact on Mohave's revenue is trivial and could not justify the administrative burdens of the phase-in.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize Staff's surrebuttal recommendations.

A. Staff's recommendations are the following:

- The standard residential customer charge should be set at $13.50 per month.
- The peak period recommendations for residential time-of-use as presented in Mr. Searcy's rebuttal testimony and the winter peak definition from Mr. Searcy's direct testimony should be approved.
- Mohave's proposed inverted blocking structure for residential time of use should be approved, subject to the condition that the cents per kWh block differential matches the block differential approved for the regular residential rate.
- There should be a $5.00 differential between the customer charges of the standard residential rate and the residential time-of-use rates.
- The existing Large Commercial and Industrial Time-of-Use rate schedule should be frozen for new customers. The frozen rate should be eliminated in Mohave's next general rate case.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF 2010 REVENUE UNDER EXISTING AND STAFF SURREBUTTAL RATES

			kWh		Adjusted	Mohave Prop. Direct	Change		Staff Surrebuttal	Change	
		Cust	Total	Avg Mn	2010	2010	$	%	2010	$	%
Residential		34,875	364,970,959	872	42,986,712	44,735,329	1,748,617	4.07%	44,715,743	1,729,031	4.02%
Irrigation Time of Use		12	1,730,345	12,016	166,306	168,026	1,720	1.03%	167,368	1,062	0.64%
Irrigation Pumping		11	2,572,007	19,485	302,194	309,962	7,768	2.57%	308,398	6,204	2.05%
Subtotal Irrigation		23	4,302,352	15,588	468,500	477,988	9,488	2.03%	475,766	7,266	1.55%
Small Comm Energy		3,201	42,164,591	1,098	4,900,351	5,177,391	277,040	5.65%	5,224,497	324,146	6.61%
Small Comm Demand		529	70,626,268	11,126	7,389,210	7,729,118	339,908	4.60%	7,720,820	331,610	4.49%
Small Comm TOU		8	1,020,044	10,625	96,177	100,936	4,759	4.95%	101,502	5,326	5.54%
Subtotal Small Comm		3,738	113,810,903	2,537	12,385,738	13,007,445	621,707	5.02%	13,046,819	661,081	5.34%
Large Comm & Industrial		118	170,994,538	4,495,062	15,775,430	16,108,634	333,204	2.11%	16,160,593	385,163	2.44%
LC&I TOU		3	564,880	15,691	48,035	67,443	19,408	40.40%	61,177	13,142	27.36%
Lighting Devices	*	1,151	1,100,103	80	98,025	103,184	5,159	5.26%	103,596	5,571	5.68%
Resale	*	1	46,862,961	3,905,247	3,698,667	3,698,667	0	0.00%	3,698,667	0	0.00%
Total Energy Sales	*	38,757	702,606,696	1,511	75,461,107	78,198,690	2,737,583	3.63%	78,262,361	2,801,253	3.71%
Other Revenue					606,899	863,547	256,647	42.29%	867,282	260,383	42.90%
Total Revenue					76,068,007	79,062,237	2,994,230	3.94%	79,129,643	3,061,636	4.02%

** Total Customers excludes Lighting Devices and Resale*

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF 2010 REVENUE UNDER EXISTING AND PROPOSED RATES (DETAIL)

		kWh		Adjusted	Cents per	Mohave Proposed	Cents per	Change under Mohave Proposal		Staff Proposed	Cents per	Change under Staff Proposal	
	Cust	Total	Avg Mn	2010	kWh	2010	kWh	$	%	2010	kWh	$	%
Residential	34,775	364,111,753	873	$ 42,878,813	11.8	$ 44,621,441	12.3	$ 1,742,628	4.06%	$ 44,602,308	12.2	$1,723,495	4.02%
Residential - Seasonal	1	549	46	$ 164	29.9	$ 235	42.8	$ 71	43.29%	$ 202	36.8	$ 38	23.15%
Residential - Net Metering	72	640,060	741	$ 81,352	12.7	$ 86,113	13.5	$ 4,761	5.85%	$ 86,089	13.5	$ 4,737	5.82%
Res - Gov	27	218,597	675	$ 26,383	12.1	$ 27,540	12.6	$ 1,157	4.38%	$ 27,144	12.4	$ 761	2.88%
Residential	34,875	364,970,959	872	$ 42,986,712	11.8	$ 44,735,329	12.3	$ 1,748,617	**4.07%**	$ 44,715,743	12.3	$1,729,031	4.02%
Irrigation Time of Use	12	1,730,345	12,016	$ 166,306	9.6	$ 168,026	9.7	$ 1,720	**1.03%**	$ 167,368	9.7	$ 1,062	0.64%
Irrigation Pumping	11	2,572,007	19,485	$ 302,194	11.7	$ 309,962	12.1	$ 7,768	**2.57%**	$ 308,398	12.0	$ 6,204	2.05%
Subtotal Irrigation	23	4,302,352	15,588	$ 468,500	10.9	$ 477,988	11.1	$ 9,488	**2.03%**	$ 475,766	11.1	$ 7,266	1.55%
Small Commercial Energy	2,930	38,541,431	1,096	$ 4,479,803	11.6	$ 4,733,078	12.3	$ 253,275	5.65%	$ 4,776,317	12.4	$ 296,514	6.62%
SC Energy Gov	267	3,559,150	1,111	$ 413,221	11.6	$ 436,237	12.3	$ 23,016	5.57%	$ 440,348	12.4	$ 27,126	6.56%
SC Energy - Net Metering	4	64,010	1,334	$ 7,327	11.4	$ 8,076	12.6	$ 749	10.22%	$ 7,832	12.2	$ 505	6.89%
Small Comm Energy	3,201	42,164,591	1,098	$ 4,900,351	11.6	$ 5,177,391	12.3	$ 277,040	**5.65%**	$ 5,224,497	12.4	$ 324,146	6.61%
Small Commercial Demand	463	63,019,478	11,343	$ 6,561,332	10.4	$ 6,854,527	10.9	$ 293,195	4.47%	$ 6,846,574	10.9	$ 285,242	4.35%
SC Demand Gov	65	7,582,510	9,721	$ 825,265	10.9	$ 871,832	11.5	$ 46,567	5.64%	$ 871,487	11.5	$ 46,222	5.60%
SC Demand - Net Metering	1	24,280		$ 2,613	10.8	$ 2,759	11.4	$ 146	5.58%	$ 2,758	11.4	$ 145	5.56%
Small Comm Demand	529	70,626,268	11,126	$ 7,389,210	10.5	$ 7,729,118	10.9	$ 339,908	**4.60%**	$ 7,720,820	10.9	$ 331,610	4.49%
Small Comm TOU	8	1,020,044	10,625	$ 96,177	9.4	$ 100,936	9.9	$ 4,759	**4.95%**	$ 101,502	10.0	$ 5,326	5.54%
Subtotal Small Comm	3,738	113,810,903	2,537	$ 12,385,738	10.9	$ 13,007,445	11.4	$ 621,707	**5.02%**	$ 13,046,819	11.5	$ 661,081	5.34%
Large Power Sec	82	76,311,058	77,552	$ 7,200,844	9.4	$ 7,578,027	9.9	$ 377,183	5.24%	$ 7,606,509	10.0	$ 405,665	5.63%
LP Gov	30	17,180,160	47,723	$ 1,842,672	10.7	$ 1,963,366	11.4	$ 120,694	6.55%	$ 1,976,562	11.5	$ 133,890	7.27%
Large Power Primary	3	8,497,320	236,037	$ 758,514	8.9	$ 781,262	9.2	$ 22,748	3.00%	$ 783,052	9.2	$ 24,538	3.23%
LP Subtransmission	1	30,204,000	2,517,000	$ 2,625,974	8.7	$ 2,493,869	8.3	$ (132,105)	-5.03%	$ 2,500,932	8.3	$ (125,042)	-4.76%
LP Substation	2	38,802,000	1,616,750	$ 3,347,425	8.6	$ 3,292,110	8.5	$ (55,315)	-1.65%	$ 3,293,539	8.5	$ (53,887)	-1.61%
Large Comm & Industrial	118	170,994,538	4,495,062	$ 15,775,430	9.2	$ 16,108,634	9.4	$ 333,204	**2.11%**	$ 16,160,593	9.5	$ 385,163	2.44%
LC&I TOU	3	564,880	15,691	$ 48,035	8.5	$ 67,443	11.9	$ 19,408	**40.40%**	$ 61,177	10.8	$ 13,142	27.36%
Lighting Devices	1,151	1,100,103	80	$ 98,025	8.9	$ 103,184	9.4	$ 5,159	**5.26%**	$ 103,596	9.4	$ 5,571	5.68%
Resale	1	46,862,961	3,905,247	$ 3,698,667	7.9	$ 3,698,667	7.9	$ -	**0.00%**	$ 3,698,667	7.9	$ -	0.00%
Total Energy Sales	38,757	702,606,696	1,511	$ 75,461,107	10.7	$ 78,198,690	11.1	$ 2,737,583	**3.63%**	$ 78,262,361	11.1	$2,801,253	3.71%
Other Revenue				$ 606,899		$ 863,547		$ 256,647	**42.29%**	$ 867,282		$ 260,383	42.90%
Total Revenue				$ 76,068,007		$ 79,062,237		$ 2,994,230	**3.94%**	$ 79,129,643		$3,061,636	4.02%

** Total Customers excludes Lighting Devices and Resale*

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

108		Billing	Proposed Rate			Proposed Revenue		
		Units	**Pur Pwr**	**Dist Wires**	**Total**	**Pur Pwr**	**Dist Wires**	**Total**
1. RESIDENTIAL SERVICE								
Residential								
Service Charge (12 Month Sum)		417,302	$ -	$ 13.50	$ 13.50	$ -	$ 5,633,577	$ 5,633,577
Energy Charge per kWh								
First	200 kWh per month	75,441,637	$ 0.079958	$ 0.013393	$ 0.093351	$ 6,032,162	$ 1,010,390	$ 7,042,552
Next	200 kWh per month	62,783,417	$ 0.079958	$ 0.013393	$ 0.093351	$ 5,020,036	$ 840,858	$ 5,860,895
Next	200 kWh per month	50,237,165	$ 0.093458	$ 0.014893	$ 0.108351	$ 4,695,065	$ 748,182	$ 5,443,247
Next	200 kWh per month	39,197,460	$ 0.093458	$ 0.014893	$ 0.108351	$ 3,663,316	$ 583,768	$ 4,247,084
Next	200 kWh per month	30,436,462	$ 0.093458	$ 0.014893	$ 0.108351	$ 2,844,531	$ 453,290	$ 3,297,821
Over	1,000 kWh per month	106,015,612	$ 0.106958	$ 0.016393	$ 0.123351	$ 11,339,218	$ 1,737,914	$ 13,077,132
Base Revenue		364,111,753				$ 33,594,329	$ 11,007,979	$ 44,602,308
PPCA Revenue							$ -	$ -
Total Revenue						$ 33,594,329	$ 11,007,979	$ 44,602,308
Residential - Seasonal								
Service Charge (12 Month Sum)		11	$ -	$ 13.50	$ 13.50	$ -	$ 149	$ 149
Energy Charge per kWh								
First	200 kWh per month	201	$ 0.079958	$ 0.013393	$ 0.093351	$ 16	$ 3	$ 19
Next	200 kWh per month	200	$ 0.079958	$ 0.013393	$ 0.093351	$ 16	$ 3	$ 19
Next	200 kWh per month	148	$ 0.093458	$ 0.014893	$ 0.108351	$ 14	$ 2	$ 16
Next	200 kWh per month	0	$ 0.093458	$ 0.014893	$ 0.108351	$ -	$ -	$ -
Next	200 kWh per month	0	$ 0.093458	$ 0.014893	$ 0.108351	$ -	$ -	$ -
Over	1,000 kWh per month	0	$ 0.106958	$ 0.016393	$ 0.123351	$ -	$ -	$ -
Base Revenue		549				$ 46	$ 156	$ 202
PPCA Revenue							$ -	$ -
Total Revenue						$ 46	$ 156	$ 202

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

108	Billing Units	Proposed Rate Pur Pwr	Proposed Rate Dist Wires	Proposed Rate Total	Proposed Revenue Pur Pwr	Proposed Revenue Dist Wires	Proposed Revenue Total
1. RESIDENTIAL SERVICE (Continued)							
Residential - Net Metering							
Service Charge (12 Month Sum)	863	$ -	$ 19.00	$ 19.00	$ -	$ 16,397	$ 16,397
Energy Charge per kWh							
First 200 kWh per month	114,805	$ 0.079958	$ 0.013393	$ 0.093351	$ 9,180	$ 1,538	$ 10,717
Next 200 kWh per month	97,201	$ 0.079958	$ 0.013393	$ 0.093351	$ 7,772	$ 1,302	$ 9,074
Next 200 kWh per month	79,816	$ 0.093458	$ 0.014893	$ 0.108351	$ 7,459	$ 1,189	$ 8,648
Next 200 kWh per month	63,706	$ 0.093458	$ 0.014893	$ 0.108351	$ 5,954	$ 949	$ 6,903
Next 200 kWh per month	49,825	$ 0.093458	$ 0.014893	$ 0.108351	$ 4,657	$ 742	$ 5,399
Over 1,000 kWh per month	234,706	$ 0.106958	$ 0.016393	$ 0.123351	$ 25,104	$ 3,848	$ 28,951
Base Revenue	640,060				$ 60,125	$ 25,963	$ 86,089
PPCA Revenue						$ -	$ -
Total Revenue					$ 60,125	$ 25,963	$ 86,089
Res - Gov							
Service Charge (12 Month Sum)	318	$ -	$ 13.50	$ 13.50	$ -	$ 4,293	$ 4,293
Energy Charge per kWh							
First 200 kWh per month	60,246	$ 0.079958	$ 0.013393	$ 0.093351	$ 4,817	$ 807	$ 5,624
Next 200 kWh per month	44,692	$ 0.079958	$ 0.013393	$ 0.093351	$ 3,573	$ 599	$ 4,172
Next 200 kWh per month	28,446	$ 0.093458	$ 0.014893	$ 0.108351	$ 2,659	$ 424	$ 3,082
Next 200 kWh per month	20,173	$ 0.093458	$ 0.014893	$ 0.108351	$ 1,885	$ 300	$ 2,186
Next 200 kWh per month	15,693	$ 0.093458	$ 0.014893	$ 0.108351	$ 1,467	$ 234	$ 1,700
Over 1,000 kWh per month	49,347	$ 0.106958	$ 0.016393	$ 0.123351	$ 5,278	$ 809	$ 6,087
Base Revenue	218,597				$ 19,679	$ 7,465	$ 27,144
PPCA Revenue						$ -	$ -
Total Revenue					$ 19,679	$ 7,465	$ 27,144
Base Revenue	364,970,959				$ 33,674,179	$ 11,041,564	$ 44,715,743
PPCA Revenue					$ -	$ -	$ -
Total Revenue					$ 33,674,179	$ 11,041,564	$ 44,715,743

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

108	Billing Units	Proposed Rate: Pur Pwr	Proposed Rate: Dist Wires	Proposed Rate: Total	Proposed Revenue: Pur Pwr	Proposed Revenue: Dist Wires	Proposed Revenue: Total
2. IRRIGATION SERVICE							
Irrigation Time of Use							
Service Charge (12 Month Sum)	144	$ -	$ 66.91	$ 66.91	$ -	$ 9,635	$ 9,635
On-Peak Demand	2,234.49	$ 8.63	$ -	$ 8.63	$ 19,284	$ -	$ 19,284
NCP Demand	8,466.81	$ -	$ 1.68	$ 1.68	$ -	$ 14,224	$ 14,224
Energy Charge per kWh	1,730,345	$ 0.071776	$ 0.000016	$ 0.071792	$ 124,197	$ 28	$ 124,225
Base Revenue					$ 143,481	$ 23,887	$ 167,368
PPCA Revenue						$ -	$ -
Total Revenue					$ 143,481	$ 23,887	$ 167,368
Irrigation Pumping							
Service Charge (12 Month Sum)	132	$ -	$ 61.76	$ 61.76	$ -	$ 8,152	$ 8,152
NCP Demand	12,025.74	$ 5.74	$ 1.68	$ 7.42	$ 69,028	$ 20,203	$ 89,231
Energy Charge per kWh	2,572,007	$ 0.072027	$ 0.010016	$ 0.082043	$ 185,254	$ 25,761	$ 211,015
Base Revenue					$ 254,282	$ 54,117	$ 308,398
PPCA Revenue						$ -	$ -
Total Revenue					$ 254,282	$ 54,117	$ 308,398
Base Revenue	4,302,352				$ 397,763	$ 78,004	$ 475,766
PPCA Revenue					$ -	$ -	$ -
Total Revenue					$ 397,763	$ 78,004	$ 475,766
3. SMALL COMMERCIAL SERVICE							
Sm Comm Demand - Net Metering							
Service Charge (12 Month Sum)	5	$ -	$ 36.03	$ 36.03	$ -	$ 180	$ 180
NCP Demand > 3 kW	73.68	$ 6.13	$ 4.69	$ 10.82	$ 452	$ 346	$ 797
Energy Charge per kWh	24,280	$ 0.072753	$ 0.000598	$ 0.073351	$ 1,766	$ 15	$ 1,781
Base Revenue					$ 2,218	$ 540	$ 2,758
PPCA Revenue						$ -	$ -
Total Revenue					$ 2,218	$ 540	$ 2,758

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

108	Billing	Proposed Rate			Proposed Revenue		
	Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
3. SMALL COMMERCIAL SERVICE (Continued)							
Small Commercial Demand							
Service Charge (12 Month Sum)	5,552	$ -	$ 36.03	$ 36.03	$ -	$ 200,039	$ 200,039
NCP Demand > 3 kW	187,060.45	$ 6.13	$ 4.69	$ 10.82	$ 1,146,681	$ 877,314	$ 2,023,994
Energy Charge per kWh	63,019,478	$ 0.072753	$ 0.000598	$ 0.073351	$ 4,584,856	$ 37,686	$ 4,622,542
Base Revenue					$ 5,731,537	$ 1,115,038	$ 6,846,574
PPCA Revenue						$ -	$ -
Total Revenue					$ 5,731,537	$ 1,115,038	$ 6,846,574
Small Commercial Energy							
Service Charge (12 Month Sum)	35,164	$ -	$ 18.50	$ 18.50	$ -	$ 650,534	$ 650,534
Energy Charge per kWh	38,541,431	$ 0.087338	$ 0.019710	$ 0.107048	$ 3,366,132	$ 759,652	$ 4,125,783
Base Revenue					$ 3,366,132	$ 1,410,186	$ 4,776,317
PPCA Revenue						$ -	$ -
Total Revenue					$ 3,366,132	$ 1,410,186	$ 4,776,317
Small Commercial - Net Metering							
Service Charge (12 Month Sum)	49	$ -	$ 20.00	$ 20.00	$ -	$ 980	$ 980
Energy Charge per kWh	64,010	$ 0.087338	$ 0.019710	$ 0.107048	$ 5,591	$ 1,262	$ 6,852
Base Revenue					$ 5,591	$ 2,242	$ 7,832
PPCA Revenue						$ -	$ -
Total Revenue					$ 5,591	$ 2,242	$ 7,832
Small Commercial TOU							
Service Charge (12 Month Sum)	91	$ -	$ 41.01	$ 41.01	$ -	$ 3,732	$ 3,732
On-Peak Demand	1,430.12	$ 14.45	$ -	$ 14.45	$ 20,665	$ -	$ 20,665
NCP kW	3,175.62	$ -	$ 4.69	$ 4.69	$ -	$ 14,894	$ 14,894
Energy Charge per kWh	1,020,044	$ 0.045399	$ 0.015590	$ 0.060989	$ 46,309	$ 15,902	$ 62,211
Base Revenue					$ 66,974	$ 34,528	$ 101,502
PPCA Revenue						$ -	$ -
Total Revenue					$ 66,974	$ 34,528	$ 101,502
SC Energy Gov							
Service Charge (12 Month Sum)	3,208	$ -	$ 18.50	$ 18.50	$ -	$ 59,348	$ 59,348
Energy Charge per kWh	3,559,150	$ 0.087338	$ 0.019710	$ 0.107048	$ 310,849	$ 70,151	$ 381,000
Base Revenue					$ 310,849	$ 129,499	$ 440,348
PPCA Revenue						$ -	$ -
Total Revenue					$ 310,849	$ 129,499	$ 440,348

Follows Structure of Mohave's Supplemental Schedule N-1.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

	108	Billing Units	Proposed Rate Pur Pwr	Proposed Rate Dist Wires	Proposed Rate Total	Proposed Revenue Pur Pwr	Proposed Revenue Dist Wires	Proposed Revenue Total
3.	**SMALL COMMERCIAL SERVICE (Continued)**							
	SC Demand Gov							
	Service Charge (12 Month Sum)	784	$ -	$ 36.03	$ 36.03	$ -	$ 28,248	$ 28,248
	NCP Demand > 3 kW	26,495.68	$ 6.13	$ 4.69	$ 10.82	$ 162,419	$ 124,265	$ 286,683
	Energy Charge per kWh	7,582,510	$ 0.072802	$ 0.000598	$ 0.073400	$ 552,022	$ 4,534	$ 556,556
	Base Revenue					$ 714,440	$ 157,047	$ 871,487
	PPCA Revenue						$ -	$ -
	Total Revenue					$ 714,440	$ 157,047	$ 871,487
	Base Revenue	113,810,903				$ 10,197,740	$ 2,849,079	$ 13,046,819
	PPCA Revenue					$ -	$ -	$ -
	Total Revenue					$ 10,197,740	$ 2,849,079	$ 13,046,819
4.	**LARGE COMMERCIAL & INDUSTRIAL SERVICE**							
	Large C&I Secondary							
	Service Charge (12 Month Sum)	983	$ -	$ 175.00	$ 175.00	$ -	$ 172,025	$ 172,025
	NCP Demand	189,369.16	$ 7.81	$ 3.22	$ 11.03	$ 1,478,973	$ 609,769	$ 2,088,742
	Energy Charge per kWh	76,311,058	$ 0.063682	$ 0.006370	$ 0.070052	$ 4,859,641	$ 486,101	$ 5,345,742
	Base Revenue					$ 6,338,614	$ 1,267,895	$ 7,606,509
	PPCA Revenue						$ -	$ -
	Total Revenue					$ 6,338,614	$ 1,267,895	$ 7,606,509
	Large C&I Primary							
	Service Charge (12 Month Sum)	36	$ -	$ 175.00	$ 175.00	$ -	$ 6,300	$ 6,300
	NCP Demand	17,172.00	$ 7.81	$ 3.22	$ 11.03	$ 134,113	$ 55,294	$ 189,407
	Energy Charge per kWh	8,497,320	$ 0.063682	$ 0.006370	$ 0.070052	$ 541,126	$ 54,128	$ 595,254
	Primary Discount on Demand & Energy		-1.00%	-1.00%	-1.00%	$ (6,752)	$ (1,157)	$ (7,910)
	Base Revenue					$ 668,487	$ 114,565	$ 783,052
	PPCA Revenue						$ -	$ -
	Total Revenue					$ 668,487	$ 114,565	$ 783,052

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

108	Billing Units	Proposed Rate Pur Pwr	Proposed Rate Dist Wires	Proposed Rate Total	Proposed Revenue Pur Pwr	Proposed Revenue Dist Wires	Proposed Revenue Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)							
Large C&I TOU-F (Proposed to be available only to customers subscribing to Large C&I TOU as of 03/01/2012)							
Service Charge (12 Month Sum)	31	$ -	$ 189.00	$ 189.00	$ -	$ 5,859	$ 5,859
On-Peak Demand	690.80	$ 11.11	$ -	$ 11.11	$ 7,675	$ -	$ 7,675
NCP kW	5,713.20	$ -	$ 3.22	$ 3.22	$ -	$ 18,397	$ 18,397
Energy Charge per kWh	564,880	$ 0.045405	$ 0.006370	$ 0.051775	$ 25,648	$ 3,598	$ 29,247
Base Revenue					$ 33,323	$ 27,854	$ 61,177
PPCA Revenue						$ -	$ -
Total Revenue					$ 33,323	$ 27,854	$ 61,177
Large C&I TOU (Proposed to be available to all Large C&I customers)							
Service Charge (12 Month Sum)	*new proposal; no test year subscription*	$ -	$ 189.00	$ 189.00	*N/A*	*N/A*	*N/A*
On-Peak Demand	*new proposal; no test year subscription*	$ 23.00	$ -	$ 23.00	*N/A*	*N/A*	*N/A*
NCP kW	*new proposal; no test year subscription*	$ -	$ 3.22	$ 3.22	*N/A*	*N/A*	*N/A*
Energy Charge per kWh	*new proposal; no test year subscription*	$ 0.045405	$ 0.006370	$ 0.051775	*N/A*	*N/A*	*N/A*
Base Revenue					*N/A*	*N/A*	*N/A*
PPCA Revenue						*N/A*	*N/A*
Total Revenue					*N/A*	*N/A*	*N/A*
Large C&I GOV							
Service Charge (12 Month Sum)	362	$ -	$ 175.00	$ 175.00	$ -	$ 63,350	$ 63,350
NCP Demand	64,343.36	$ 7.81	$ 3.22	$ 11.03	$ 502,522	$ 207,186	$ 709,707
Energy Charge per kWh	17,180,160	$ 0.063682	$ 0.006370	$ 0.070052	$ 1,094,067	$ 109,438	$ 1,203,505
Base Revenue					$ 1,596,589	$ 379,973	$ 1,976,562
PPCA Revenue						$ -	$ -
Total Revenue					$ 1,596,589	$ 379,973	$ 1,976,562
LC&I Trans (Current TOU) *Billed at Subtransmission Delivery Level*							
Service Charge (12 Month Sum)	12	$ -	$ 175.00	$ 175.00	$ -	$ 2,100	$ 2,100
NCP kW	53,106.00	$ 7.81	$ 3.22	$ 11.03	$ 414,758	$ 171,001	$ 585,759
Energy Charge per kWh	30,204,000	$ 0.063682	$ 0.006370	$ 0.070052	$ 1,923,451	$ 192,399	$ 2,115,851
Subtransmission Discount on Demand & Energy		-7.50%	-7.50%	-7.50%	$ (175,366)	$ (27,413)	$ (202,778)
Base Revenue					$ 2,162,843	$ 338,088	$ 2,500,932
PPCA Revenue						$ -	$ -
Total Revenue					$ 2,162,843	$ 338,088	$ 2,500,932

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

	108		Billing	Proposed Rate			Proposed Revenue		
			Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
4.	**LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)**								
	LP Substation	*Billed at Substation Delivery Level*							
	Service Charge (12 Month Sum)		24	$ -	$ 175.00	$ 175.00	$ -	$ 4,200	$ 4,200
	NCP kW		67,500.00	$ 7.81	$ 3.22	$ 11.03	$ 527,175	$ 217,350	$ 744,525
	Energy Charge per kWh		38,802,000	$ 0.063682	$ 0.006370	$ 0.070052	$ 2,470,989	$ 247,169	$ 2,718,158
	Substation Discount on Demand & Energy			-5.00%	-5.00%	-5.00%	$ (149,908)	$ (23,436)	$ (173,344)
	Base Revenue						$ 2,848,256	$ 445,283	$ 3,293,539
	PPCA Revenue						$ -	$ -	$ -
	Total Revenue						$ 2,848,256	$ 445,283	$ 3,293,539
	Base Revenue		171,559,418				$ 13,648,112	$ 2,573,658	$ 16,221,770
	PPCA Revenue						$ -	$ -	$ -
	Total Revenue						$ 13,648,112	$ 2,573,658	$ 16,221,770
5.	**LIGHTING SERVICE**								
	175 W MVL	102 kWh per month	6,039	$ 6.13	$ 0.98	$ 7.11	$ 37,019	$ 5,918	$ 42,937
	100 W HPS	51 kWh per month	2,594	$ 3.07	$ 5.39	$ 8.46	$ 7,964	$ 13,982	$ 21,945
	175 W MVL CO	101 kWh per month	320	$ 6.07	$ 0.51	$ 6.58	$ 1,942	$ 163	$ 2,106
	100 W HPS CO	51 kWh per month	3,644	$ 3.07	$ 2.34	$ 5.41	$ 11,187	$ 8,527	$ 19,714
	250 W HPS	130 kWh per month	1,211	$ 7.81	$ 6.14	$ 13.95	$ 9,458	$ 7,436	$ 16,893
	Base Revenue		13,808				$ 67,570	$ 36,026	$ 103,596
	PPCA Revenue							$ -	$ -
	Total Revenue						$ 67,570	$ 36,026	$ 103,596
	kWh		1,100,103						
6.	**RESALE REVENUE**								
	Base Revenue						$ 3,222,980	$ 475,687	$ 3,698,667
	PPCA Revenue						$ -	$ -	$ -
	Total Revenue		46,862,961				$ 3,222,980	$ 475,687	$ 3,698,667
7.	**TOTAL REVENUE**								
	Base Revenue		702,606,696				$ 61,208,344	$ 17,054,017	$ 78,262,361
	PPCA Revenue						$ -	$ -	$ -
	Other Revenue						$ -	$ 867,282	$ 867,282
	Total						$ 61,208,344	$ 17,921,299	$ 79,129,643

Follows Structure of Mohave's Supplemental Schedule N-1.0

MOHAVE ELECTRIC COOPERATIVE, INC.
RESIDENTIAL COMPARISON OF EXISTING MOHAVE PROPOSED AND STAFF SURREBUTTAL RATES - 2010 USAGE

	Existing Rate	Mohave Proposed Rate	% Change	Staff Surrebuttal Rate	% Change
Service Charge	$9.50	$16.50	73.7%	$ 13.50	42.1%
Energy Charge, per kWh					
First 400	$0.083190	$0.096373	15.8%	$0.093351	12.2%
Next 600	$0.083190	$0.106373	27.9%	$0.108351	30.2%
Over 1,000	$0.083190	$0.116373	39.9%	$0.123351	48.3%
PPCA Factor	$0.023685	($0.001850)	-107.8%	$0.000000	-100.0%
Total Energy Charge plus PPCA					
First 400	$0.106875	$0.094523	-11.6%	$0.093351	-12.7%
Next 600	$0.106875	$0.104523	-2.2%	$0.108351	1.4%
Over 1,000	$0.106875	$0.114523	7.2%	$0.123351	15.4%

kWh Usage		Monthly Cust[1]	Existing Rate	Mohave Proposed Rate	Mohave Change fr. Existing	Mohave % Change fr. Existing	Staff Proposed Rate	Staff Change fr. Existing	Staff % Change fr. Existing
0		1,009	$9.50	$16.50	$7.00	73.68%	$13.50	$4.00	42.11%
100		2,913	$20.19	$25.95	$5.76	28.56%	$22.84	$2.65	13.12%
200		2,687	$30.88	$35.40	$4.53	14.67%	$32.17	$1.30	4.19%
400		5,213	$52.25	$54.31	$2.06	3.94%	$50.84	($1.41)	-2.70%
800		9,166	$95.00	$96.12	$1.12	1.18%	$94.18	($0.82)	-0.86%
1,000		3,212	$116.38	$117.02	$0.65	0.56%	$115.85	($0.52)	-0.45%
2,000		7,881	$223.25	$231.55	$8.30	3.72%	$239.20	$15.95	7.15%
3,000		2,466	$330.13	$346.07	$15.94	4.83%	$362.55	$32.43	9.82%
5,000		738	$543.88	$575.12	$31.24	5.74%	$609.26	$65.38	12.02%
8,000		54	$864.50	$918.68	$54.18	6.27%	$979.31	$114.81	13.28%
Over		4							
860	**Average**		**$101.41**	**$102.39**	$0.98	0.96%	**$100.68**	($0 73)	-0.72%
637	**Median**		**$77.58**	**$79.08**	$1.50	1.94%	**$76.52**	($1.06)	-1.37%

Note 1 - Customers with usage from the previous block to this block