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Transcript Exhibit(s)

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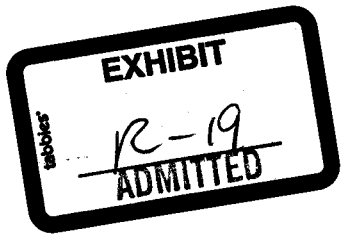
ARIZONA WATER COMPANY

DOCKET NO. W-01445A-08-0440



SURREBUTTAL TESTIMONY ON REQUIRED REVENUE

OF

TIMOTHY J. COLEY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 7, 2009

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INTRODUCTION

Q. Please state your name for the record.

A. My name is Timothy J. Coley.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on June 12, 2009.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company's rebuttal comments and non-responses pertaining to adjustments I recommended in my direct testimony.

SUMMARY OF ADJUSTMENTS

Q. What areas will you address in your surrebuttal testimony?

A. My surrebuttal testimony will address RUCO's recommended rate base adjustments and other issues for the following three groups for Arizona Water Company's (hereafter referred to as "AWC" or "Company") seventeen water systems:

...

Eastern Group	Western Group	Northern Group
Superstition	Casa Grande	Lakeside
Bisbee	Stanfield	Overgaard
Sierra Vista	White Tank	Sedona
San Manuel	Ajo	Pinewood
Oracle	Coolidge	Rimrock
Winkleman		
Miami		

For revenue requirement purposes, RUCO analyzed each system on a stand-alone basis. Mr. William A. Rigsby will address RUCO's surrebuttal operating income adjustments and cost of capital recommendations. RUCO Director, Ms. Jodi A. Jerich, will file testimony regarding RUCO's rate design on August 12, 2009.

SURREBUTTAL RATE BASE ADJUSTMENTS TO THE EASTERN, WESTERN, AND NORTHERN GROUPS:

Surrebuttal Adjustment No. 1 – Utility Plant in Service ("UPIS") and Accumulated Depreciation Manual Reconstruction;

Surrebuttal Adjustment No. 2 – Remove RUCO's Post Test Year Phoenix Office Plant Direct Adjustment;

...

Surrebuttal Adjustment No. 3 – Remove Plant Held for Future Use ("PHFFU") and Record Certain Retirements;

Surrebuttal Adjustment No. 4 – Miscellaneous Adjustment for Three Systems (Casa Grande, Pinewood, and Sedona);

Surrebuttal Adjustment No. 5 – To Account for Customer Deposits in Rate Base (except for the Sedona System, which removed a Post Test Year Arizona Department of Transportation Project);

Surrebuttal Adjustment No. 6 – Working Capital Adjustment (except for the Sedona System, which accounted for the Customer Deposits in rate base);

Surrebuttal Adjustment No. 7 – Working Capital Adjustment (unique to the Sedona System only).

OTHER ISSUES:

<u>Oracle System Depreciation Expense</u>

There is an error in the Company's depreciation expense calculation for the Oracle System that will be discussed in detail later in this testimony.

SURREBUTTAL SUPPORTING SCHEDULES

To support the adjustments in my surrebuttal testimony, I am presenting Surrebuttal Schedules numbered SURR TJC & WAR-1, pages 1 and 2, SURR TJC & WAR-2, SURR TJC & WAR-3, SURR TJC & WAR-7, SURR TJC & WAR-8, and SURR TJC & WAR-15, which are filed concurrently in my surrebuttal testimony.

ORIGINAL COST RATE BASE ("OCRB") ADJUSTMENTS

RUCO Surrebuttal OCRB Adjustment No. 1 – Utility Plant in Service ("UPIS") and Accumulated Depreciation

Q. Please briefly summarize your surrebuttal rate base adjustment #1.

A. This adjustment is common to all systems and reflects RUCO's recommended UPIS and accumulated depreciation balances since the last rate case for each Group. I started with the last Commission approved balance and reconstructed all plant additions, retirements, and adjustments at the approved depreciation rates.

Q. Did the Company respond in rebuttal to RUCO regarding this adjustment?

A. No.

...

Q. Does RUCO maintain that this adjustment is a proper recommendation?

A. Yes. The Company performed the same analysis as RUCO with similar results but did not make the necessary adjustments that resulted from the analysis.

Q. Does RUCO provide the adjustments in its surrebuttal testimony and schedules?

A. Yes. The adjustments are on Schedule TJC-2 and WAR-2. The supporting details are on Schedules TJC-3 and WAR-3.

<u>RUCO Rate Base Adjustment #2 – Remove Post-Test Year Phoenix Office Plant</u>

Q. Please explain RUCO surrebuttal rate base adjustment #2.

A. RUCO reversed its direct testimony adjustment #2 pertaining to Phoenix Office post-test year plant.

Q. Does RUCO no longer recommend removing the post-test year plant associated with the Phoenix Office?

A. That is correct.

...

Q. What reason(s) does RUCO give in reversing its adjustment to the post-test year Phoenix Office plant?

A. RUCO determined that the post-test year plant related to the Phoenix Office went into service two days after the test year.

Q. Doesn't RUCO normally oppose post-test year plant as creating mismatches with other test year ratemaking elements?

A. Yes. RUCO believes mismatches of ratemaking elements do exist when post-test year plant is allowed in the historical test year. However, in this instance, RUCO makes exception because the plant went into service two days after the test year.

<u>RUCO Rate Base Adjustment #3 – Remove Plant Held for Future Use ("PHFFU") and Record Certain Retirements</u>

Q. Please briefly explain the basis of RUCO surrebuttal rate base adjustment #3.

A. The basis of this adjustment derived from information the Company provided in Staff data request BKB 11.16, which identified certain PHFFU and retirements that the Company failed to record, which were included in its rate application. This adjustment is simply a conforming adjustment to that data response to properly account for those plant items.

...

Q. Does the Company agree with this adjustment to remove PHFFU from UPIS and to account for the retirements accordingly?

A. The Company agrees with the appropriate recording to account for the retirements.

Q. What is the Company's position regarding the PHFFU?

A. The Company is requesting the PHFFU be rate based in this proceeding, with the exception of the Carroll Canyon well in the Sedona System.

Q. What reason does the Company give to support its request that the plant be rate based in this proceeding?

A. The Company essentially says that it has definitive plans for the plant in question.

Q. Is the PHFFU providing service to the existing customers today?

A. Not to my knowledge.

Q. Did the Company provide any time frame as to when the plant in question would be placed into service?

A. Yes. A Company engineering witness provided rebuttal testimony indicating that the plant would be placed in service any where from 2010 to 2012.

...

Q. Isn't 2010 and 2012 three to five years after the test year?

A. Yes.

Q. What reason(s) did the Company engineering witness provide for the long delays in placing the plant in service?

A. The Company stated repeatedly "Due to the Company's deteriorated earnings, this project has been temporarily delayed. The Company plans to move forward with this project in the future when earnings and the housing market improve."

Q. Does RUCO consider that response to be a bit speculative?

A. Yes. The Company claims in rebuttal testimony that if either RUCO or Staff's revenue requirement recommendations were adopted by the Commission in this proceeding the Company would essentially be in the same financial position that led it to file this rate application (See Company Exhibit JMR-RB1). Secondly, no one is certain when the housing market will improve. Clearly, the Carroll Canyon well is not used and useful either during the test year or at present.

Q. Did Staff make a similar adjustment in its direct testimony schedules?

A. Yes. The only difference between RUCO and Staff is a slight difference in the amount of the adjustments. The difference is due to some plant RUCO identified as being in service whereas Staff did not.

Q. What is RUCO's recommendation regarding the PHFFU?

A. Notwithstanding the Company's three to five year "definitive" plans, RUCO recommends the Commission not allow rate base treatment for the PHFFU as shown in RUCO's surrebuttal adjustment #3. The adjustments are on Schedule TJC-2 and WAR-2. The supporting details are on Schedules TJC-3 and WAR-3.

RUCO Rate Base Adjustment #4 – Remove Other Post Test Year Plant in Pinewood/Sedona Systems and Adjust Net Regulatory Asset in Casa Grande

Pinewood System

Q. Please explain RUCO's surrebuttal rate base adjustment #4 that removes post-test year plant from the Pinewood System?

A. This adjustment removes an electrical panel box from the Pinewood System that was not in service, to my knowledge, at the time of this writing.

Q. Does that mean that this particular post test year plant was not in service clearly one and a half years after the test year ended?

A. That is correct.

...

Q. What is the Company's reason for requesting rate base treatment for plant that was placed into service eighteen months after the test year?

A. AWC claims that the Company and Arizona Public Service ("APS") have been in some sort of disagreement or misunderstanding regarding the power connection for the electrical panel in question. In rebuttal testimony, the Company stated that APS continues to delay establishing service. However, "APS has informed the Company that the new panels will be energized by July 20, 2009."

Q. Does RUCO know if APS has established service for the electrical panels in the Pinewood System as stated above?

A. No. Neither would it matter in RUCO's recommendation if the electrical panels have been energized as stated above nor if they have not yet been energized.

Q. Why wouldn't it matter to RUCO if the electrical panels are now energized and in service?

A. Post-test year plant is mismatched with the other historical test year ratemaking elements (i.e. revenues, expenses, and other rate base elements) of the test year. Matching is a fundamental principle of accounting and ratemaking. The absence of matching misrepresents the meaning and usefulness of operating income and rate base for measuring the fairness and reasonableness in setting rates. RUCO recognizes that

the Commission has allowed post-test year plant in past decisions. In recognition of that fact, RUCO has allowed post-test year plant additions in special circumstances, unusual circumstances, when public safety and health issues are of concern,[1] and when it is reasonably close to the test year end (i.e. six-months post test year).

Q. Does the Company recognize any parameters or limitations relating to post-test year plant?

A. The Company hasn't explicitly stated what its restrictions are regarding post-test year plant in this case. In past AWC rate cases, the Company usually stated that its post-test year plant is revenue neutral and within one year of the year. It is plain that is no longer the case now.

Q. What recommendation does RUCO make regarding the electrical panels in the Pinewood System?

A. RUCO believes the post-test year electrical panels should be disallowed for the reasons previously mentioned. The adjustments are on Schedule WAR-2. The supporting details are on Schedule WAR-3 in RUCO surrebuttal rate base adjustment #4 that decreases UPIS by $40,553 and decreases accumulated depreciation by $1,191.

[1] RUCO has allowed all arsenic and nitrate post test year plant in this rate proceeding because it constitutes a public health and/or safety concern.

Sedona System

Please explain RUCO's surrebuttal adjustment #4 that reduces post-test year plant by $2,011,576 and decreases accumulated depreciation by $21,940 in the Sedona System.

A. This adjustment consists of two post-test year wells. The first well is located in the Valley Vista section of the Sedona System. Its well identification number is #13. As shown on RUCO Exhibit 1, the Company's data response to Staff data request BKB 11.16 designates that this well was "placed in service in November '08." That is more than ten full months after the test year.

Q. Does post-test year plant that exceeds Arizona's fundamental historical test year concept for ratemaking by more than ten full months not meet RUCO's criteria for allowing post-test year plant?

A. It does not meet RUCO's criteria for inclusion in rate base. As stated earlier, RUCO has allowed post-test year plant additions in special circumstances, unusual circumstances, when public safety and health issues are of concern,[2] and when it is reasonably close to the test year end (i.e. six-months post test year). To stray so far outside the test year, Arizona's use of a historical test year would have to be abandoned.

[2] RUCO has allowed all arsenic and nitrate post-test year plant in this rate proceeding because it constitutes a public health and safety concern.

Q. What adjustment is necessary to remove the Valley Vista well #13 that did not enter service until November 2008?

A. The necessary adjustment reduces UPIS by $1,597,759 and reduces accumulated depreciation by $20,691.

Q. Did the Company accept RUCO's adjustment to remove the Valley Vista well #13 from UPIS?

A. No. Although, the Company did accept the second part of rate base adjustment #4 that removed the Carroll Canyon well from the Sedona System.

Q. What adjustment was necessary to remove the Carroll Canyon well from the Sedona System?

A. The necessary adjustment reduces UPIS by $413,817 and reduces accumulated depreciation by $1,249. The adjustments are on Schedule WAR-2. The supporting details are on Schedule WAR-3.

<u>Casa Grande System</u>

Q. Please explain RUCO's surrebuttal adjustment #4 in the Casa Grande System?

A. This is a conforming adjustment that the Company accepted from Commission Staff. The Company had improperly amortized a regulatory asset in its rate application.

Q. What adjustment was necessary to properly reflect the net balance of the regulatory asset?

A. It was necessary to reduce the regulatory asset by $14,289 to properly reflect the balance of that asset. This reduces the rate base by the same amount. The adjustments are on Schedule TJC-2. The supporting details are on Schedule TJC-3.

RUCO Rate Base Adjustment #5 – Customer Deposits Except in the Sedona System

Q. Please explain RUCO's surrebuttal rate base adjustment #5 for all the systems except the Sedona System.

A. This is a conforming adjustment to the Company's acceptance of a Staff adjustment. The Company failed to include the customer deposits in its rate base (B) Schedules. The adjustment includes the customer deposits as a reduction to rate base since the deposits are a non-investor form of capital. The adjustments are on Schedule TJC-2 and WAR-2. The supporting details are on Schedules TJC-3 and WAR-3.

Q. Please explain RUCO's rate base adjustment #5 for the Sedona System.

A. This adjustment removes 35 percent of an Arizona Department of Transportation ("ADOT") post-test year project. RUCO's reason for the adjustment was due to an informal data response to Staff dated May 13, 2009. The data response indicated the project was 65 percent complete

as of November 2008. RUCO removed the other 35 percent of the Company's post-test year plant adjustment as failing to meet RUCO's criteria for inclusion in rate base in this case.

Q. Did the Company accept RUCO's rate base adjustment #5 for the Sedona System?

A. No.

Q. Did the Company provide a reason for not accepting RUCO's adjustment to the ADOT post-test year project in the Sedona System?

A. Yes. The Company stated, "Like arsenic and nitrate treatment, the costs related to this project were mandated by the government." Therefore, the Company erroneously concluded from my direct testimony that RUCO automatically allows all post-test year plant that is mandated by government.

Q. Please further clarify RUCO's position regarding post-test year plant that is mandated by the government.

A. As stated earlier in my testimony, RUCO allowed all post test year plant in this case that was related to arsenic and nitrate treatment plant for public health and safety reasons. The caveat here regarding the ADOT project is that RUCO does not view this project to be a public health and/or safety

issue. However, RUCO did recommend that 65 percent of the project to be included in UPIS.

Q. What adjustment is necessary to recognize that 35 percent of the ADOT project was not in service as of November 2008?

A. RUCO removed $661,738 of post-test year plant from UPIS and reduced accumulated depreciation by $5,923. The adjustments are on Schedule WAR-2. The supporting details are on Schedule WAR-3.

RUCO Rate Base Adjustment #6 – Working Capital Except in the Sedona System

Q. Briefly summarize RUCO's adjustments that it made in direct testimony to the Company's direct testimony lead/lag study in determining the Company's cash working capital requirements.

A. RUCO made six adjustments to the Company's lead/lag study as follows:

	RUCO	Company
1. Purchased Power Lag Days	35.92	30.87
2. Purchased Water Lead/Lag Days	Dependent on System	(0.11)
3. Chemical Expense Lead/Lag Days	20.43	(18.11)
4. Other O&M Lead/Lag Days	30.00	(9.27)
5. Rate Case Expense	Exclude	Include
6. Cost of Equity	Exclude	Include

Q. What was RUCO's rationale for making the purchased power adjustment shown above to the Company's lead/lag study?

A. It was RUCO's understanding that the Company used the last Northern Group rate case lead/lag study. After further review, the Company used the Northern Group's lead/lag study as a starting point and made its own adjustments to it. RUCO believes that a more appropriate starting point would have been the most recent Western Group's lead/lag study. RUCO's purchased power lag days adjustment used the 35.92 lag days that were used in the most recent Western Group case. Upon further review, the Company actually did their own lead/lag study for purchased power expense.

Q. Please explain why RUCO believes the Western Group's lead/lag study is more appropriate than the Northern Group's in this case.

A. The data in the Western Group's lead/lag study is much more current than the Northern Group. The Western Group's lead/lag study was based on a 2003 test year whereas the Northern Group's was based on a 1999 test year.

Q. Does RUCO accept the Company's purchased power expense lag days in surrebuttal testimony?

A. Yes. RUCO accepts the Company's 30.87 lag days for all seventeen systems in surrebuttal testimony.

Q. What was RUCO's rationale for making the purchased water adjustment shown above to the Company's lead/lag study?

A. The Company utilized the same lead days for its lead/lag study for all systems that had purchased water expense. There are five systems (Superstition, Casa Grande, San Manuel, Ajo, and White Tanks) that have considerable purchased water expense while a couple of other systems have marginal purchased water expenses. Two of the systems (Superstition and Casa Grande) purchase Central Arizona Project ("CAP") surface water. San Manuel purchases water from BHP Mining Company. Ajo purchases water from Ajo Improvement District. White Tanks purchases water from Arizona-American Water Company.

Q. Wouldn't one think that the purchased water expense lead/lag days be different in each system if purchased from different sources rather than the Company's use of (0.11) lead days across all systems?

A. Yes. The Superstition and Casa Grande Systems should be quite similar since those two purchase CAP water, but the other three systems should be quite different.

Q. Did RUCO perform a purchased water expense lead/lag study for the five systems with considerable purchased water expense?

A. Yes. RUCO reviewed the purchased water expense invoices of each of the five systems with considerable amount of purchased water.

Q. Did the Company accept RUCO's purchased water expense lead/lag days?

A. No.

Q. What reason(s) did the Company give for not accepting the purchased water expense lead/lag days?

A. Company witness Mr. Reiker stated, "I found that while he did account for CAP prepayments in the Casa Grande system, he did not account for any water purchased from the CAP in the Superstition system."

Q. Is Mr. Reiker correct that RUCO overlooked the CAP prepayments?

A. Yes, but not entirely. RUCO's lead/lag study for the Superstition System did not contain the CAP prepayments. RUCO requested all purchased water invoices for the five systems. We went through and recorded each invoice at the Company's Phoenix Office that the Company provided to RUCO. Either the Company inadvertently failed to provide the Superstition CAP prepayment invoices or RUCO overlooked them.

Q. Shouldn't an analyst immediately recognize that the CAP prepayment invoices were missing from the study?

A. Yes, in most situations that would be true. However, the Superstition System purchases CAP water and wheels it to the City of Mesa for treatment. Then, Mesa wheels it back into the Superstition distribution

system. RUCO accounted for all of the treatment costs and simply assumed that the CAP prepayment costs were captured in the City of Mesa invoices.

Q. Has RUCO corrected the absence of the CAP prepayments?

A. Yes.

Q. How did RUCO correct for the absence of the CAP prepayments?

A. RUCO used the CAP prepayment lead days resulting from the Casa Grande study. As Mr. Reiker rightfully points out, RUCO did account for the CAP prepayments in the Casa Grande System properly. CAP contracts have general terms for payments for all buyers. Therefore, the lead days for the CAP prepayments that result in the number of purchased water expense lead days to be used in the lead/lag study should be very comparable because the terms are the same for both Superstition and Casa Grande.

Q. What were the purchased water expense lead/lag days for each of the five systems?

A. The following lead/lag days resulting from RUCO's study are now as follows:

Superstition	(40.09)
Casa Grande	(55.31)

Ajo	38.97
White Tanks	121.16
San Manuel	26.04

The adjustments are on the respective Schedules TJC-6, page 2.

Q. Did the Company accept RUCO's lead/lag days for chemical expenses?

A. No. After further study and review, RUCO accepts the Company's (18.11) lead days for chemical expenses.

Q. Did the Company accept RUCO's 30 lead/lag days for other operating and maintenance expenses?

A. No. After further study and review, RUCO accepts the Company's (9.27) lead days for other operating and maintenance expenses.

Q. Did the Company accept RUCO's recommendation to exclude rate case expense from the lead/lag study?

A. Yes.

Q. Did the Company accept RUCO's adjustment to remove the cost of equity from the lead/lag study?

A. No. All of RUCO's reasons for not including the cost of equity in the lead/lag study are provided in Coley direct testimony on pages 23-25.

Q. Please explain RUCO's surrebuttal rate base adjustment #6 for the Sedona System.

A. This adjustment includes the customer deposits in rate base and reduces rate base accordingly. This adjustment is fully explained earlier in rate base adjustment #5.

RUCO Rate Base Adjustment #7 – Working Capital in the Sedona System

Q. Please explain the adjustment to working capital for the Sedona System.

A. This adjustment is explained in RUCO rate base adjustment #6.

OTHER ISSUES

Q. Please explain any other issues RUCO has with the Company's rate application and rebuttal schedules.

A. There is an error in both the Company's direct rate application and rebuttal schedules.

Q. Please explain the error that exists in the rate application and rebuttal schedules.

A. The error exists in the Oracle System and was pointed out to Mr. Reiker via phone conversation. When the Company filed its rebuttal testimony and schedules, the error was not corrected. The Company correctly removes the Saddlebrook System plant in the B Schedules that were recorded in the Oracle System. The Company does not remove the

Saddlebrook plant in its C-2 Appendix Schedules when calculating the depreciation expense for the Oracle System. Rather than having a positive pro-forma adjustment for Oracle's depreciation expense, the adjustment should be negative once the Saddlebrook plant balances are removed from Oracle's depreciation schedule.

Q. Did RUCO make the correct adjustment to properly reflect the plant balances for Oracle excluding the Saddlebrook plant in its depreciation expense schedule?

A. There is no special adjustment necessary to account for the error in the Company's schedules. RUCO's total recommended plant balances are the same in its TJC-2 and TJC-11. Whereas, the Company's B-2 Schedules for Oracle has a total plant balance of $6,084,930 and the Company's C-2 Appendix depreciation schedule has a total depreciable plant balance of $7,071,105, which is a difference of $986,175. The $986,175 difference represents the total pro-forma adjustment shown on Company Schedule B-2.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

TABLE OF CONTENTS TO TJC SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 43,424,545	$ 42,476,176
2	Adjusted Operating Income (Loss)	$ 1,850,403	$ 1,914,522
3	Current Rate of Return (L2 / L1)	4.26%	4.51%
4	Required Operating Income (L5 X L1)	$ 4,261,800	$ 3,113,504
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 2,411,397	$ 1,198,982
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 3,927,284	$ 1,952,703
9	Adjusted Test Year Revenue	$ 11,939,904	$ 11,939,904
10	Proposed Annual Revenue (L8 + L9)	$ 15,867,189	$ 13,892,607
11	Required Percentage Increase in Revenue (L8 / L9)	32.89%	16.35%
12	Consolidated Revenue Adjustment	$ 937,341	$ 157,394
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ 4,864,542	$ 2,110,097
14	Required Revenue Under Proposed Consolidation	$ 16,804,800	$ 14,050,001
15	Required Percentage Increase in Revenue Under Proposed Consolidation	40.74%	17.67%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4)	$ 3,113,504			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2)	1,914,522			
13	Required Increase In Operating Income (L11 - L12)		$ 1,198,982		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 1,020,016			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	266,295			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 753,721		
17	Total Required Increase In Revenue (L13 + L16)		$ 1,952,703		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. TJC-1, Pg 1, Col. (B), L12)			$ 13,892,607	
19	Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23)			9,759,087	
20	Synchronized Interest (Col. (C), L37)			1,490,914	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 2,642,606	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 184,137
24	Fed. Taxable Income (L21 - L23)			$ 2,458,470	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ 6,250	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ 8,500	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ 91,650	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 721,980	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 835,880
31	Combined Federal and State Income Tax (L23 + L30)				$ 1,020,016
32	Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23)				$ 266,295
33	RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23)				$ 753,721
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 42,476,176	
36	Weighted Avg. Cost of Debt (Sch. TJC-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 1,490,914	

Arizona Water Company
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Superstition System - Surrebuttal
Schedule TJC-2

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 12,555	$ 1	$ 12,556
2	Source of Supply Plant	5,528,785	(801,061)	4,727,724
3	Pumping Plant	7,692,391	(59,595)	7,632,796
4	Water Treatment Plant	6,885,736	(3,057)	6,882,679
5	Transmission & Distribution Plant	68,915,456	(502)	68,914,955
6	General Plant	4,555,508	(7,089)	4,548,420
7	Total Gross Plant in Service	$ 93,590,431	$ (871,303)	$ 92,719,129
8	Accumulated Depreciation	(17,724,938)	212,613	(17,512,325)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 75,865,493	$ (658,690)	$ 75,206,804
10	Advances In Aid Of Const.	$ (18,952,520)	$ -	$ (18,952,520)
11	Contribution In Aid Of Const.	$ (10,888,555)	$ -	$ (10,888,555)
12	Accumulated Amortization Of CIAC	1,733,417	-	1,733,417
13	NET CIAC (L5 + L6)	$ (9,155,138)	$ -	$ (9,155,138)
14	Deferred Income Tax	$ (4,779,751)	$ -	$ (4,779,751)
15	Customer Deposits	$ -	$ (196,185)	$ (196,185)
16	Allowance For Working Capital	$ 446,461	$ (93,495)	$ 352,966
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 43,424,545	$ (948,369)	$ 42,476,176

References:
Column (A): Company Schedule B-1
Column (B): Schedule RLM-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Superstition System - Surrebuttal
Schedule TJC-3

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 12,555	$ 1	$ -	$ -	$ -	$ -	$ -	$ 12,556
2	Source of Supply Plant	5,528,785	(8)	-	(801,053)	-	-	-	4,727,724
3	Pumping Plant	7,692,391	6,292	-	(65,887)	-	-	-	7,632,796
4	Water Treatment Plant	6,885,736	(0)	-	(3,057)	-	-	-	6,882,679
5	Transmission & Distribution Plant	68,915,456	(2)	-	(500)	-	-	-	68,914,955
6	General Plant	4,555,508	(1)	-	(7,088)	-	-	-	4,548,420
7	Total Gross Plant in Service	$ 93,590,431	$ 6,282	$ -	$ (877,585)	$ -	$ -	$ -	$ 92,719,129
8	Accumulated Depreciation	$ (17,724,938)	(22,612)	-	235,225	-	-	-	(17,512,325)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 75,865,493	$ (16,330)	$ -	$ (642,360)	$ -	$ -	$ -	$ 75,206,804
10	Advances In Aid Of Const.	$ (18,952,520)	$ -	$ -	$ -	$ -	$ -	$ -	$ (18,952,520)
11	Contribution In Aid Of Const.	$ (10,888,555)	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,888,555)
12	Accumulated Amortization Of CIAC	1,733,417	-	-	-	-	-	-	1,733,417
13	NET CIAC (L5 + L6)	$ (9,155,138)	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,155,138)
14	Deferred Income Tax	$ (4,779,751)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,779,751)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (196,185)	$ -	$ (196,185)
16	Allowance For Working Capital	$ 446,461	$ -	$ -	$ -	$ -	$ -	$ (93,495)	$ 352,966
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18									
	Rounding	$ -							$ -
	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 43,424,545	$ (16,330)	$ -	$ (642,360)	$ -	$ (196,185)	$ (93,495)	$ 42,476,176

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
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Superstition System - Surrebuttal
Schedule TJC-7
Page 1 of 1

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 8,708,171	$ -	$ 8,708,171	$ 1,952,703	$ 10,660,874
2	Commercial	2,125,918	-	2,125,918	-	2,125,918
3	Industrial	35,010	-	35,010	-	35,010
4	Private Fire Service	8,293	-	8,293	-	8,293
5	Other Water Revenues	346,347	-	346,347	-	346,347
6	Total Water Revenues	$ 11,223,738	$ -	$ 11,223,738	$ 1,952,703	$ 13,176,441
7	Miscellaneous	$ 716,166	$ -	$ 716,166	$ -	$ 716,166
8	Total Operating Revenues	$ 11,939,904	$ -	$ 11,939,904	$ 1,952,703	$ 13,892,607
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ 1,019,696	$ -	$ 1,019,696	$ -	$ 1,019,696
10	Other	48,540	-	48,540	-	48,540
11	Pumping Expenses:					
12	Purchased Power	1,170,704	-	1,170,704	-	1,170,704
13	Purchased Gas	-	-	-	-	-
14	Other	307,004	-	307,004	-	307,004
15	Water Treatment Expenses	389,035	-	389,035	-	389,035
16	Transmission & Distribution Expenses	1,339,694	-	1,339,694	-	1,339,694
17	Customer Accounting Expenses	945,427	-	945,427	-	945,427
18	Sales Expense	5,489	-	5,489	-	5,489
19	Administrative & General Expenses	1,591,413	(57,875)	1,533,538	-	1,533,538
20	Total Operations & Maintenance Expense	$ 6,817,003	$ (57,875)	$ 6,759,128	$ -	$ 6,759,128
21	Depreciation & Amortization Expenses	$ 2,169,209	$ (50,843)	$ 2,118,366	$ -	$ 2,118,366
	Taxes					
22	Federal Income Taxes	$ 123,547	$ 94,676	$ 218,223	$ 617,657	$ 835,880
23	State Income Taxes	27,216	20,856	48,072	136,064	184,137
24	Property Taxes	815,362	(68,099)	747,263	-	747,263
25	Other	137,164	(2,834)	134,330	-	134,330
26	Total Taxes	$ 1,103,289	$ 44,599	$ 1,147,888	$ 753,721	$ 1,901,609
27	Total Operating Expenses	$ 10,089,501	$ (64,119)	$ 10,025,382	$ 753,721	$ 10,779,103
28	Operating Income	$ 1,850,403	$ 64,119	$ 1,914,522	$ 1,198,982	$ 3,113,504

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 8,708,171	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,708,171
2	Commercial	2,125,918	-	-	-	-	-	-	-	-	-	-	2,125,918
3	Industrial	35,010	-	-	-	-	-	-	-	-	-	-	35,010
4	Private Fire Service	8,293	-	-	-	-	-	-	-	-	-	-	8,293
5	Other Water Revenues	346,347	-	-	-	-	-	-	-	-	-	-	346,347
6	Total Water Revenues	$ 11,223,738	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,223,738
7	Miscellaneous	$ 716,166	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 716,166
8	Total Operating Revenues	$ 11,939,904	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,939,904
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ 1,019,696	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,019,696
10	Other	48,540	-	-	-	-	-	-	-	-	-	-	48,540
11	Pumping Expenses:	-	-	-	-	-	-	-	-	-	-	-	-
12	Purchased Power	1,170,704	-	-	-	-	-	-	-	-	-	-	1,170,704
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	307,004	-	-	-	-	-	-	-	-	-	-	307,004
15	Water Treatment Expenses	389,035	-	-	-	-	-	-	-	-	-	-	389,035
16	Transmission & Distribution Expenses	1,339,694	-	-	-	-	-	-	-	-	-	-	1,339,694
17	Customer Accounting Expenses	945,427	-	-	-	-	-	-	-	-	-	-	945,427
18	Sales Expense	5,489	-	-	-	-	-	-	-	-	-	-	5,489
19	Administrative & General Expenses	1,591,413	(37,927)	-	(3,184)	-	-	(137)	-	-	(16,627)	-	1,533,538
20	Total Operations & Maintenance Expense	$ 6,817,003	$ (37,927)	$ -	$ (3,184)	$ -	$ -	$ (137)	$ -	$ -	$ (16,627)	$ -	$ 6,759,128
21	Depreciation & Amortization Expenses	$ 2,169,209	$ -	$ -	$ -	$ -	$ -	$ -	$ (50,843)	$ -	$ -	$ -	$ 2,118,366
	Taxes												
22	Federal Income Taxes	$ 123,547	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 94,676	$ 218,223
23	State Income Taxes	27,216	-	-	-	-	-	-	-	-	-	20,856	48,072
24	Property Taxes	815,362	-	-	-	-	-	-	-	(68,099)	-	-	747,263
25	Other	137,164	-	(2,834)	-	-	-	-	-	-	-	-	134,330
26	Total Taxes	$ 1,103,289	$ -	$ (2,834)	$ -	$ -	$ -	$ -	$ -	$ (68,099)	$ -	$ 115,532	$ 1,147,888
27	Total Operating Expenses	$ 10,089,501	$ (37,927)	$ (2,834)	$ (3,184)	$ -	$ -	$ (137)	$ (50,843)	$ (68,099)	$ (16,627)	$ 115,532	$ 10,025,382
28	Operating Income	$ 1,850,403	$ 37,927	$ 2,834	$ 3,184	$ -	$ -	$ 137	$ 50,843	$ 68,099	$ 16,627	$ (115,532)	$ 1,914,522

ADJUSTMENTS:
1 - Labor Expense - Normalize OT Hours in Test Year
2 - Payroll Tax Expense Related to Adjustment 1
3 - 401(K) Expense Related to Adjustment 1
4 - Reverse Adjustment for Conservation
5 - Purchased Power Revenues
6 - Insurance Expense
7 - Depreciation Expense
8 - Property Tax Expense
9 - Rate Case Expense

REFERENCE:
Testimony, WAR And Schedule TJC-9 Page, 1 of 3
Testimony, WAR And Schedule TJC-9 Page, 2 of 3
Testimony, WAR And Schedule TJC-9 Page, 3 of 3
Testimony WAR
Testimony WAR
Testimony, WAR And Schedule TJC-10
Testimony, WAR And Schedule TJC-11
Testimony, WAR And Schedule TJC-12
Testimony, WAR And Schedule TJC-13

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Long-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

TABLE OF CONTENTS TO TJC SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 4,660,984	$ 4,622,091
2	Adjusted Operating Income (Loss)	$ 168,796	$ 181,625
3	Current Rate of Return (L2 / L1)	3.62%	3.93%
4	Required Operating Income (L5 X L1)	$ 457,441	$ 338,799
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 288,646	$ 157,175
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 470,098	$ 255,980
9	Adjusted Test Year Revenue	$ 1,723,475	$ 1,723,475
10	Proposed Annual Revenue (L8 + L9)	$ 2,193,573	$ 1,979,454
11	Required Percentage Increase in Revenue (L8 / L9)	27.28%	14.85%
12	Consolidated Revenue Adjustment	$ (106,651)	$ 19,875
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ 363,319	$ 275,855
14	Required Revenue Under Proposed Consolidation	$ 2,086,472	$ 1,999,329
15	Required Percentage Increase in Revenue Under Proposed Consolidation	21.08%	16.01%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4)	$ 338,799			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2)	181,625			
13	Required Increase In Operating Income (L11 - L12)		$ 157,175		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 110,994			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	12,189			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 98,805		
17	Total Required Increase In Revenue (L13 + L16)		$ 255,980		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. TJC-1, Pg 1, Col. (B), L12)			$ 1,979,454	
19	Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23)			1,529,661	
20	Synchronized Interest (Col. (C), L37)			162,235	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 287,558	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 20,037
24	Fed. Taxable Income (L21 - L23)			$ 267,521	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 90,957	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 90,957
31	Combined Federal and State Income Tax (L23 + L30)				$ 110,994
32	Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23)				$ 12,189
33	RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23)				$ 98,805
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 4,622,091	
36	Weighted Avg. Cost of Debt (Sch. TJC-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 162,235	

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 43,332	$ -	$ 43,332
2	Source of Supply Plant	849,846	-	849,846
3	Pumping Plant	889,639	6,328	895,967
4	Water Treatment Plant	46,503	-	46,503
5	Transmission & Distribution Plant	7,664,743	-	7,664,743
6	General Plant	820,594	(704)	819,890
7	Total Gross Plant in Service	$ 10,314,658	$ 5,624	$ 10,320,281
8	Accumulated Depreciation	(4,218,432)	(10,167)	(4,228,599)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 6,096,226	$ (4,543)	$ 6,091,683
10	Advances in Aid Of Const.	$ (258,981)	$ -	$ (258,981)
11	Contribution in Aid of Const.	$ (452,659)	$ -	$ (452,659)
12	Accumulated Amortization of CIAC	106,681	-	106,681
13	NET CIAC (L5 + L6)	$ (345,978)	$ -	$ (345,978)
14	Deferred Income Tax	$ (954,417)	$ -	$ (954,417)
15	Customer Deposits	$ -	$ (17,600)	$ (17,600)
16	Allowance for Working Capital	$ 124,134	$ (16,750)	$ 107,384
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 4,660,984	$ (38,893)	$ 4,622,091

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 43,332	$ -	$ -	$ -	$ -	$ -	$ -	$ 43,332
2	Source of Supply Plant	849,846	-	-	-	-	-	-	849,846
3	Pumping Plant	889,639	6,328	-	-	-	-	-	895,967
4	Water Treatment Plant	46,503	-	-	-	-	-	-	46,503
5	Transmission & Distribution Plant	7,664,743	-	-	-	-	-	-	7,664,743
6	General Plant	820,594	-	-	(704)	-	-	-	819,890
7	Total Gross Plant in Service	$ 10,314,658	$ 6,328	$ -	$ (704)	$ -	$ -	$ -	$ 10,320,281
8	Accumulated Depreciation	(4,218,432)	(10,913)	-	746	-	-	-	(4,228,599)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 6,096,226	$ (4,585)	$ -	$ 42	$ -	$ -	$ -	$ 6,091,683
10	Advances in Aid Of Const.	$ (258,981)	$ -	$ -	$ -	$ -	$ -	$ -	$ (258,981)
11	Contribution in Aid of Const.	$ (452,659)	$ -	$ -	$ -	$ -	$ -	$ -	$ (452,659)
12	Accumulated Amortization of CIAC	106,681	-	-	-	-	-	-	106,681
13	NET CIAC (L5 + L6)	$ (345,978)	$ -	$ -	$ -	$ -	$ -	$ -	$ (345,978)
14	Deferred Income Tax	$ (954,417)	$ -	$ -	$ -	$ -	$ -	$ -	$ (954,417)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (17,600)	$ -	$ (17,600)
16	Allowance for Working Capital	$ 124,134	$ -	$ -	$ -	$ -	$ -	$ (16,750)	$ 107,384
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 4,660,984	$ (4,585)	$ -	$ 42	$ -	$ (17,600)	$ (16,750)	$ 4,622,091

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimony)
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 1,192,596	$ -	$ 1,192,596	$ 255,980	$ 1,448,576
2	Commercial	491,700	-	491,700	-	491,700
3	Industrial	2,302	-	2,302	-	2,302
4	Private Fire Service	908	-	908	-	908
5	Other Water Revenues	12,628	-	12,628	-	12,628
6	Total Water Revenues	$ 1,700,135	$ -	$ 1,700,135	$ 255,980	$ 1,956,115
7	Miscellaneous	$ 23,340	$ -	$ 23,340	$ -	$ 23,340
8	Total Operating Revenues	$ 1,723,475	$ -	$ 1,723,475	$ 255,980	$ 1,979,454
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	2,443	-	2,443	-	2,443
11	Pumping Expenses:	-				
12	Purchased Power	224,856	-	224,856	-	224,856
13	Purchased Gas	615	-	615	-	615
14	Other	50,077	-	50,077	-	50,077
15	Water Treatment Expenses	32,933	-	32,933	-	32,933
16	Transmission & Distribution Expenses	270,483	-	270,483	-	270,483
17	Customer Accounting Expenses	179,534	-	179,534	-	179,534
18	Sales Expense	529	-	529	-	529
19	Administrative & General Expenses	392,583	(11,551)	381,032	-	381,032
20	Total Operations & Maintenance Expense	$ 1,154,054	$ (11,551)	$ 1,142,502	$ -	$ 1,142,502
21	Depreciation & Amortization Expenses	$ 261,462	$ (4,015)	$ 257,447	$ -	$ 257,447
	Taxes					
22	Federal Income Taxes	$ (2,100)	$ 12,088	$ 9,988	$ 80,969	$ 90,957
23	State Income Taxes	(463)	2,663	2,200	17,837	20,037
24	Property Taxes	114,911	(11,448)	103,463	-	103,463
25	Other	26,815	(566)	26,249	-	26,249
26	Total Taxes	$ 139,163	$ 2,737	$ 141,900	$ 98,805	$ 240,706
27	Total Operating Expenses	$ 1,554,679	$ (12,829)	$ 1,541,850	$ 98,805	$ 1,640,655
28	Operating Income	$ 168,796	$ 12,829	$ 181,625	$ 157,175	$ 338,799

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 1,192,596	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,192,596
2	Commercial	491,700	-	-	-	-	-	-	-	-	-	-	491,700
3	Industrial	2,302	-	-	-	-	-	-	-	-	-	-	2,302
4	Private Fire Service	908	-	-	-	-	-	-	-	-	-	-	908
5	Other Water Revenues	12,628	-	-	-	-	-	-	-	-	-	-	12,628
6	Total Water Revenues	$ 1,700,135	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,700,135
7	Miscellaneous	$ 23,340	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,340
8	Total Operating Revenues	$ 1,723,475	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,723,475
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	2,443	-	-	-	-	-	-	-	-	-	-	2,443
11	Pumping Expenses:					-							
12	Purchased Power	224,856	-	-	-	-	-	-	-	-	-	-	224,856
13	Purchased Gas	615	-	-	-	-	-	-	-	-	-	-	615
14	Other	50,077	-	-	-	-	-	-	-	-	-	-	50,077
15	Water Treatment Expenses	32,933	-	-	-	-	-	-	-	-	-	-	32,933
16	Transmission & Distribution Expenses	270,483	-	-	-	-	-	-	-	-	-	-	270,483
17	Customer Accounting Expenses	179,534	-	-	-	-	-	-	-	-	-	-	179,534
18	Sales Expense	529	-	-	-	-	-	-	-	-	-	-	529
19	Administrative & General Expenses	392,583	(7,573)	-	(636)	-	-	(23)	-	-	(3,320)	-	381,032
20	Total Operations & Maintenance Expense	$ 1,154,054	$ (7,573)	$ -	$ (636)	$ -	$ -	$ (23)	$ -	$ -	$ (3,320)	$ -	$ 1,142,502
21	Depreciation & Amortization Expenses	$ 261,462	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,015)	$ -	$ -	$ -	$ 257,447
	Taxes												
22	Federal Income Taxes	$ (2,100)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,088	$ 9,988
23	State Income Taxes	(463)	-	-	-	-	-	-	-	-	-	2,663	2,200
24	Property Taxes	114,911	-	-	-	-	-	-	-	(11,448)	-	-	103,463
25	Other	26,815	-	(566)	-	-	-	-	-	-	-	-	26,249
26	Total Taxes	$ 139,163	$ -	$ (566)	$ -	$ -	$ -	$ -	$ -	$ (11,448)	$ -	$ 14,751	$ 141,900
27	Total Operating Expenses	$ 1,554,679	$ (7,573)	$ (566)	$ (636)	$ -	$ -	$ (23)	$ (4,015)	$ (11,448)	$ (3,320)	$ 14,751	$ 1,541,850
28	Operating Income	$ 168,796	$ 7,573	$ 566	$ 636	$ -	$ -	$ 23	$ 4,015	$ 11,448	$ 3,320	$ (14,751)	$ 181,625

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule TJC-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule TJC-10
7 - Depreciation Expense	Testimony, WAR And Schedule TJC-11
8 - Property Tax Expense	Testimony, WAR And Schedule TJC-12
9 - Rate Case Expense	Testimony, WAR And Schedule TJC-13
10 Income Tax	Testimony, WAR And Schedule TJC-14

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

TABLE OF CONTENTS TO TJC SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 2,520,716	$ 2,501,385
2	Adjusted Operating Income (Loss)	$ 275,060	$ 280,323
3	Current Rate of Return (L2 / L1)	10.91%	11.21%
4	Required Operating Income (L5 X L1)	$ 247,390	$ 183,352
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ (27,670)	$ (96,972)
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ (45,064)	$ (157,931)
9	Adjusted Test Year Revenue	$ 1,461,897	$ 1,461,897
10	Proposed Annual Revenue (L8 + L9)	$ 1,416,833	$ 1,303,966
11	Required Percentage Increase in Revenue (L8 / L9)	-3.08%	-10.80%
12	Consolidated Revenue Adjustment	$ 106,651	17,425
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ 61,586	$ (140,506)
14	Required Revenue Under Proposed Consolidation	$ 1,523,034	$ 1,321,391
15	Required Percentage Increase in Revenue Under Proposed Consolidation	4.20%	-9.61%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4)	$ 183,352			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2)	280,323			
13	Required Increase In Operating Income (L11 - L12)		$ (96,972)		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 60,068			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	121,028			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ (60,960)		
17	Total Required Increase In Revenue (L13 + L16)		$ (157,931)		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. TJC-1, Pg 1, Col. (B), L12)			$ 1,303,966	
19	Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23)			1,060,547	
20	Synchronized Interest (Col. (C), L37)			87,799	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 155,621	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 10,844
24	Fed. Taxable Income (L21 - L23)			$ 144,777	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 49,224	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 49,224
31	Combined Federal and State Income Tax (L23 + L30)				$ 60,068
32	Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23)				$ 121,028
33	RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23)				$ (60,960)
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 2,501,385	
36	Weighted Avg. Cost of Debt (Sch. TJC-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 87,799	

Arizona Water Company
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Test Year Ended December 31, 2007

Sierra Vista System - Surrebuttal
Schedule TJC-2

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 756	$ -	$ 756
2	Source of Supply Plant	688,417	-	688,417
3	Pumping Plant	719,189	-	719,189
4	Water Treatment Plant	92,922	-	92,922
5	Transmission & Distribution Plant	5,348,207	-	5,348,207
6	General Plant	546,855	-	546,855
7	Total Gross Plant in Service	$ 7,396,345	$ -	$ 7,396,345
8	Accumulated Depreciation	(2,113,607)	6,701	(2,106,905)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 5,282,738	$ 6,701	$ 5,289,440
10	Advances in Aid Of Const.	$ (1,453,186)	$ -	$ (1,453,186)
11	Contribution in Aid of Const.	$ (1,089,317)	$ -	$ (1,089,317)
12	Accumulated Amortization of CIAC	226,089	-	226,089
13	NET CIAC (L5 + L6)	$ (863,228)	$ -	$ (863,228)
14	Deferred Income Tax	$ (494,457)	$ -	$ (494,457)
15	Customer Deposits	$ -	$ (15,925)	$ (15,925)
16	Allowance for Working Capital	$ 48,849	$ (10,107)	$ 38,742
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 2,520,716	$ (19,331)	$ 2,501,385

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 756	$ -	$ -	$ -	$ -	$ -	$ -	$ 756
2	Source of Supply Plant	688,417	-	-	-	-	-	-	688,417
3	Pumping Plant	719,189	-	-	-	-	-	-	719,189
4	Water Treatment Plant	92,922	-	-	-	-	-	-	92,922
5	Transmission & Distribution Plant	5,348,207	-	-	-	-	-	-	5,348,207
6	General Plant	546,855	-	-	-	-	-	-	546,855
7	Total Gross Plant in Service	$ 7,396,345	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,396,345
8	Accumulated Depreciation	(2,113,607)	6,701	-	-	-	-	-	(2,106,905)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 5,282,738	$ 6,701	$ -	$ -	$ -	$ -	$ -	$ 5,289,440
10	Advances in Aid Of Const.	$ (1,453,186)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,453,186)
11	Contribution in Aid of Const.	$ (1,089,317)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,089,317)
12	Accumulated Amortization of CIAC	226,089	-	-	-	-	-	-	226,089
13	NET CIAC (L5 + L6)	$ (863,228)	$ -	$ -	$ -	$ -	$ -	$ -	$ (863,228)
14	Deferred Income Tax	$ (494,457)	$ -	$ -	$ -	$ -	$ -	$ -	$ (494,457)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (15,925)	$ -	$ (15,925)
16	Allowance for Working Capital	$ 48,849	$ -	$ -	$ -	$ -	$ -	$ (10,107)	$ 38,742
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 2,520,716	$ 6,701	$ -	$ -	$ -	$ (15,925)	$ (10,107)	$ 2,501,385

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Intentionally Left Blank
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Sierra Vista System - Surrebuttal
Schedule TJC-7
Page 1 of 1

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 1,067,828	$ -	$ 1,067,828	$ (157,931)	$ 909,896
2	Commercial	346,169	-	346,169	-	346,169
3	Industrial	-	-	-	-	-
4	Private Fire Service	1,924	-	1,924	-	1,924
5	Other Water Revenues	29,331	-	29,331	-	29,331
6	Total Water Revenues	$ 1,445,253	$ -	$ 1,445,253	$ (157,931)	$ 1,287,321
7	Miscellaneous	$ 16,645	$ -	$ 16,645	$ -	$ 16,645
8	Total Operating Revenues	$ 1,461,897	$ -	$ 1,461,897	$ (157,931)	$ 1,303,966
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	2,096	-	2,096	-	2,096
11	Pumping Expenses:	-				
12	Purchased Power	220,661	-	220,661	-	220,661
13	Purchased Gas	698	-	698	-	698
14	Other	46,020	-	46,020	-	46,020
15	Water Treatment Expenses	22,454	-	22,454	-	22,454
16	Transmission & Distribution Expenses	213,548	-	213,548	-	213,548
17	Customer Accounting Expenses	134,508	-	134,508	-	134,508
18	Sales Expense	275	-	275	-	275
19	Administrative & General Expenses	152,251	(5,992)	146,259	-	146,259
20	Total Operations & Maintenance Expense	$ 792,510	$ (5,992)	$ 786,518	$ -	$ 786,518
21	Depreciation & Amortization Expenses	$ 186,533	$ (2,248)	$ 184,285	$ -	$ 184,285
	Taxes					
22	Federal Income Taxes	$ 93,535	$ 5,644	$ 99,179	$ (49,955)	$ 49,224
23	State Income Taxes	20,605	1,243	21,848	(11,005)	10,844
24	Property Taxes	80,115	(3,618)	76,497	-	76,497
25	Other	13,539	(293)	13,246	-	13,246
26	Total Taxes	$ 207,794	$ 2,976	$ 210,771	$ (60,960)	$ 149,811
27	Total Operating Expenses	$ 1,186,838	$ (5,263)	$ 1,181,574	$ (60,960)	$ 1,120,615
28	Operating Income	$ 275,060	$ 5,263	$ 280,323	$ (96,972)	$ 183,352

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 1,067,828	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,067,828
2	Commercial	346,169	-	-	-	-	-	-	-	-	-	-	346,169
3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-
4	Private Fire Service	1,924	-	-	-	-	-	-	-	-	-	-	1,924
5	Other Water Revenues	29,331	-	-	-	-	-	-	-	-	-	-	29,331
6	Total Water Revenues	$ 1,445,253	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,445,253
7	Miscellaneous	$ 16,645	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,645
8	Total Operating Revenues	$ 1,461,897	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,461,897
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	2,096	-	-	-	-	-	-	-	-	-	-	2,096
11	Pumping Expenses:												
12	Purchased Power	220,661	-	-	-	-	-	-	-	-	-	-	220,661
13	Purchased Gas	698	-	-	-	-	-	-	-	-	-	-	698
14	Other	46,020	-	-	-	-	-	-	-	-	-	-	46,020
15	Water Treatment Expenses	22,454	-	-	-	-	-	-	-	-	-	-	22,454
16	Transmission & Distribution Expenses	213,548	-	-	-	-	-	-	-	-	-	-	213,548
17	Customer Accounting Expenses	134,508	-	-	-	-	-	-	-	-	-	-	134,508
18	Sales Expense	275	-	-	-	-	-	-	-	-	-	-	275
19	Administrative & General Expenses	152,251	(3,923)	-	(329)	-	-	(19)	-	-	(1,720)	-	146,259
20	Total Operations & Maintenance Expense	$ 792,510	$ (3,923)	$ -	$ (329)	$ -	$ -	$ (19)	$ -	$ -	$ (1,720)	$ -	$ 786,518
21	Depreciation & Amortization Expenses	$ 186,533	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,248)	$ -	$ -	$ -	$ 184,285
	Taxes												
22	Federal Income Taxes	$ 93,535	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,644	$ 99,179
23	State Income Taxes	20,605	-	-	-	-	-	-	-	-	-	1,243	21,848
24	Property Taxes	80,115	-	-	-	-	-	-	-	(3,618)	-	-	76,497
25	Other	13,539	-	(293)	-	-	-	-	-	-	-	-	13,246
26	Total Taxes	$ 207,794	$ -	$ (293)	$ -	$ -	$ -	$ -	$ -	$ (3,618)	$ -	$ 6,887	$ 210,771
27	Total Operating Expenses	$ 1,186,838	$ (3,923)	$ (293)	$ (329)	$ -	$ -	$ (19)	$ (2,248)	$ (3,618)	$ (1,720)	$ 6,887	$ 1,181,574
28	Operating Income	$ 275,060	$ 3,923	$ 293	$ 329	$ -	$ -	$ 19	$ 2,248	$ 3,618	$ 1,720	$ (6,887)	$ 280,323

ADJUSTMENTS:
1 - Labor Expense - Normalize OT Hours in Test Year
2 - Payroll Tax Expense Related to Adjustment 1
3 - 401(K) Expense Related to Adjustment 1
4 - Reverse Adjustment for Conservation
5 - Purchased Power Revenues
6 - Insurance Expense
7 - Depreciation Expense
8 - Property Tax Expense
9 - Rate Case Expense

REFERENCE:
Testimony, WAR And Schedule TJC-9 Page, 1 of 3
Testimony, WAR And Schedule TJC-9 Page, 2 of 3
Testimony, WAR And Schedule TJC-9 Page, 3 of 3
Testimony WAR
Testimony WAR
Testimony, WAR And Schedule TJC-10
Testimony, WAR And Schedule TJC-11
Testimony, WAR And Schedule TJC-12
Testimony, WAR And Schedule TJC-13

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

TABLE OF CONTENTS TO TJC SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

San Manuel System - Surrebuttal
Schedule TJC-1
Page 1 of 1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 2,035,209	$ 2,041,060
2	Adjusted Operating Income (Loss)	$ (47,524)	$ (42,235)
3	Current Rate of Return (L2 / L1)	-2.34%	-2.07%
4	Required Operating Income (L5 X L1)	$ 199,741	$ 149,610
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 247,264	$ 191,845
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 402,704	$ 312,445
9	Adjusted Test Year Revenue	$ 812,359	$ 812,359
10	Proposed Annual Revenue (L8 + L9)	$ 1,215,223	$ 1,124,804
11	Required Percentage Increase in Revenue (L8 / L9)	49.57%	38.46%
12	Consolidated Revenue Adjustment	$ -	$ 9,183
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ -	$ 321,629
14	Required Revenue Under Proposed Consolidation	$ -	$ 1,133,987
15	Required Percentage Increase in Revenue Under Proposed Consolidation	-	39.59%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-13

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 2,035,209	$ 2,041,060
2	Adjusted Operating Income (Loss)	$ (47,524)	$ (42,235)
3	Current Rate of Return (L2 / L1)	-2.34%	-2.07%
4	Required Operating Income (L5 X L1)	$ 199,741	$ 149,610
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 247,264	$ 191,845
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 402,704	$ 312,445
9	Adjusted Test Year Revenue	$ 812,359	$ 812,359
10	Proposed Annual Revenue (L8 + L9)	$ 1,215,223	$ 1,124,804
11	Required Percentage Increase in Revenue (L8 / L9)	49.57%	38.46%
12	Consolidated Revenue Adjustment	$ -	$ 9,183
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ -	$ 321,629
14	Required Revenue Under Proposed Consolidation	$ -	$ 1,133,987
15	Required Percentage Increase in Revenue Under Proposed Consolidation	-	39.59%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-13

Arizona Water Company
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Test Year Ended December 31, 2007

San Manuel System - Surrebuttal
Schedule TJC-2

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 488	$ -	$ 488
2	Source of Supply Plant	175,502	-	175,502
3	Pumping Plant	376,086	2,058	378,144
4	Water Treatment Plant	1,398,624	-	1,398,624
5	Transmission & Distribution Plant	1,712,957	-	1,712,957
6	General Plant	458,818	-	458,818
7	Total Gross Plant in Service	$ 4,122,476	$ 2,058	$ 4,124,534
8	Accumulated Depreciation	(997,040)	33,929	(963,111)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 3,125,436	$ 35,986	$ 3,161,423
10	Advances in Aid Of Const.	$ (73,164)	$ -	$ (73,164)
11	Contribution in Aid of Const.	$ (742,146)	$ -	$ (742,146)
12	Accumulated Amortization of CIAC	7,505	-	7,505
13	NET CIAC (L5 + L6)	$ (734,641)	$ -	$ (734,641)
14	Deferred Income Tax	$ (321,972)	$ -	$ (321,972)
15	Customer Deposits	$ -	$ (5,425)	$ (5,425)
16	Allowance for Working Capital	$ 39,551	$ (24,710)	$ 14,840
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 2,035,209	$ 5,851	$ 2,041,060

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 488	$ -	$ -	$ -	$ -	$ -	$ -	$ 488
2	Source of Supply Plant	175,502	-	-	-	-	-	-	175,502
3	Pumping Plant	376,086	2,058	-	-	-	-	-	378,144
4	Water Treatment Plant	1,398,624	-	-	-	-	-	-	1,398,624
5	Transmission & Distribution Plant	1,712,957	-	-	-	-	-	-	1,712,957
6	General Plant	458,818	-	-	-	-	-	-	458,818
7	Total Gross Plant in Service	$ 4,122,476	$ 2,058	$ -	$ -	$ -	$ -	$ -	$ 4,124,534
8	Accumulated Depreciation	(997,040)	33,929	-	-	-	-	-	(963,111)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 3,125,436	$ 35,986	$ -	$ -	$ -	$ -	$ -	$ 3,161,423
10	Advances in Aid Of Const.	$ (73,164)	$ -	$ -	$ -	$ -	$ -	$ -	$ (73,164)
11	Contribution in Aid of Const.	$ (742,146)	$ -	$ -	$ -	$ -	$ -	$ -	$ (742,146)
12	Accumulated Amortization of CIAC	7,505	-	-	-	-	-	-	7,505
13	NET CIAC (L5 + L6)	$ (734,641)	$ -	$ -	$ -	$ -	$ -	$ -	$ (734,641)
14	Deferred Income Tax	$ (321,972)	$ -	$ -	$ -	$ -	$ -	$ -	$ (321,972)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (5,425)	$ -	$ (5,425)
16	Allowance for Working Capital	$ 39,551	$ -	$ -	$ -	$ -	$ -	$ (24,710)	$ 14,840
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 2,035,209	$ 35,986	$ -	$ -	$ -	$ (5,425)	$ (24,710)	$ 2,041,060

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Intentionally Left Blank
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

San Manuel System - Surrebuttal
Schedule TJC-7

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 646,904	$ -	$ 646,904	$ 312,445	$ 959,350
2	Commercial	143,872	-	143,872	-	143,872
3	Industrial	-	-	-	-	-
4	Private Fire Service	56	-	56	-	56
5	Other Water Revenues	11,113	-	11,113	-	11,113
6	Total Water Revenues	$ 801,946	$ -	$ 801,946	$ 312,445	$ 1,114,391
7	Miscellaneous	$ 10,413	$ -	$ 10,413	$ -	$ 10,413
8	Total Operating Revenues	$ 812,359	$ -	$ 812,359	$ 312,445	$ 1,124,804
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ 241,318	$ -	$ 241,318	$ -	$ 241,318
10	Other	6,907	-	6,907	-	6,907
11	Pumping Expenses:	-				
12	Purchased Power	38,358	-	38,358	-	38,358
13	Purchased Gas	-	-	-	-	-
14	Other	34,669	-	34,669	-	34,669
15	Water Treatment Expenses	40,816	-	40,816	-	40,816
16	Transmission & Distribution Expenses	145,743	-	145,743	-	145,743
17	Customer Accounting Expenses	104,642	-	104,642	-	104,642
18	Sales Expense	497	-	497	-	497
19	Administrative & General Expenses	140,854	(3,899)	136,955	-	136,955
20	Total Operations & Maintenance Expense	$ 753,804	$ (3,899)	$ 749,904	$ -	$ 749,904
21	Depreciation & Amortization Expenses	$ 106,134	$ (1,342)	$ 104,792	$ -	$ 104,792
	Taxes					
22	Federal Income Taxes	$ (63,368)	$ 4,704	$ (58,664)	$ 98,829	$ 40,166
23	State Income Taxes	(13,959)	1,036	(12,923)	21,771	8,848
24	Property Taxes	68,170	(5,596)	62,573	-	62,573
25	Other	9,102	(191)	8,911	-	8,911
26	Total Taxes	$ (56)	$ (47)	$ (103)	$ 120,600	$ 120,498
27	Total Operating Expenses	$ 859,882	$ (5,288)	$ 854,594	$ 120,600	$ 975,194
28	Operating Income	$ (47,524)	$ 5,288	$ (42,235)	$ 191,845	$ 149,610

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJ'TD
	Operating Revenues												
1	Residential	$ 646,904	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 646,904
2	Commercial	143,872	-	-	-	-	-	-	-	-	-	-	143,872
3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-
4	Private Fire Service	56	-	-	-	-	-	-	-	-	-	-	56
5	Other Water Revenues	11,113	-	-	-	-	-	-	-	-	-	-	11,113
6	Total Water Revenues	$ 801,946	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 801,946
7	Miscellaneous	$ 10,413	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,413
8	Total Operating Revenues	$ 812,359	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 812,359
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ 241,318	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 241,318
10	Other	6,907	-	-	-	-	-	-	-	-	-	-	6,907
11	Pumping Expenses:												
12	Purchased Power	38,358	-	-	-	-	-	-	-	-	-	-	38,358
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	34,669	-	-	-	-	-	-	-	-	-	-	34,669
15	Water Treatment Expenses	40,816	-	-	-	-	-	-	-	-	-	-	40,816
16	Transmission & Distribution Expenses	145,743	-	-	-	-	-	-	-	-	-	-	145,743
17	Customer Accounting Expenses	104,642	-	-	-	-	-	-	-	-	-	-	104,642
18	Sales Expense	497	-	-	-	-	-	-	-	-	-	-	497
19	Administrative & General Expenses	140,854	(2,555)	-	(214)	-	-	(10)	-	-	(1,120)	-	136,955
20	Total Operations & Maintenance Expense	$ 753,804	$ (2,555)	$ -	$ (214)	$ -	$ -	$ (10)	$ -	$ -	$ (1,120)	$ -	$ 749,904
21	Depreciation & Amortization Expenses	$ 106,134	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,342)	$ -	$ -	$ -	$ 104,792
	Taxes												
22	Federal Income Taxes	$ (63,368)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,704	$ (58,664)
23	State Income Taxes	(13,959)	-	-	-	-	-	-	-	-	-	1,036	(12,923)
24	Property Taxes	68,170	-	-	-	-	-	-	-	(5,596)	-	-	62,573
25	Other	9,102	-	(191)	-	-	-	-	-	-	-	-	8,911
26	Total Taxes	$ (56)	$ -	$ (191)	$ -	$ -	$ -	$ -	$ -	$ (5,596)	$ -	$ 5,740	$ (103)
27	Total Operating Expenses	$ 959,882	$ (2,555)	$ (191)	$ (214)	$ -	$ -	$ (10)	$ (1,342)	$ (5,596)	$ (1,120)	$ 5,740	$ 854,594
28	Operating Income	$ (47,524)	$ 2,555	$ 191	$ 214	$ -	$ -	$ 10	$ 1,342	$ 5,596	$ 1,120	$ (5,740)	$ (42,235)

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule TJC-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule TJC-10
7 - Depreciation Expense	Testimony, WAR And Schedule TJC-11
8 - Property Tax Expense	Testimony, WAR And Schedule TJC-12
9 - Rate Case Expense	Testimony, WAR And Schedule TJC-13

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

Arizona Water Company
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Oracle System - Surrebuttal

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WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 2,412,232	$ 2,393,683
2	Adjusted Operating Income (Loss)	$ 194,248	$ 214,630
3	Current Rate of Return (L2 / L1)	8.05%	8.97%
4	Required Operating Income (L5 X L1)	$ 236,743	$ 175,457
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 42,494	$ (39,173)
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 69,208	$ (63,798)
9	Adjusted Test Year Revenue	$ 1,126,215	$ 1,126,215
10	Proposed Annual Revenue (L8 + L9)	$ 1,195,423	$ 1,062,417
11	Required Percentage Increase in Revenue (L8 / L9)	6.15%	-5.66%
12	Consolidated Revenue Adjustment	$ -	$ 8,846
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ -	$ (54,952)
14	Required Revenue Under Proposed Consolidation	$ -	$ 1,071,263
15	Required Percentage Increase in Revenue Under Proposed Consolidation	-	-4.88%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4)	$ 175,457			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2)	214,630			
13	Required Increase In Operating Income (L11 - L12)		$ (39,173)		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 57,482			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	82,107			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ (24,625)		
17	Total Required Increase In Revenue (L13 + L16)		$ (63,798)		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. TJC-1, Pg 1, Col. (B), L12)			$ 1,062,417	
19	Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23)			829,478	
20	Synchronized Interest (Col. (C), L37)			84,018	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 148,920	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 10,377
24	Fed. Taxable Income (L21 - L23)			$ 138,543	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 47,105	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 47,105
31	Combined Federal and State Income Tax (L23 + L30)				$ 57,482
32	Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23)				$ 82,107
33	RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23)				$ (24,625)
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 2,393,683	
36	Weighted Avg. Cost of Debt (Sch. TJC-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 84,018	

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RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 627	$ -	$ 627
2	Source of Supply Plant	571,108	-	571,108
3	Pumping Plant	951,836	-	951,836
4	Water Treatment Plant	104,121	-	104,121
5	Transmission & Distribution Plant	4,194,584	-	4,194,584
6	General Plant	262,652	-	262,652
7	Total Gross Plant in Service	$ 6,084,930	$ -	$ 6,084,930
8	Accumulated Depreciation	(2,307,793)	(1,038)	(2,308,831)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 3,777,137	$ (1,038)	$ 3,776,099
10	Advances in Aid Of Const.	$ (432,749)	$ -	$ (432,749)
11	Contribution in Aid of Const.	$ (623,732)	$ -	$ (623,732)
12	Accumulated Amortization of CIAC	93,964	-	93,964
13	NET CIAC (L5 + L6)	$ (529,768)	$ -	$ (529,768)
14	Deferred Income Tax	$ (436,962)	$ -	$ (436,962)
15	Customer Deposits	$ -	$ (7,460)	$ (7,460)
16	Allowance for Working Capital	$ 34,574	$ (10,051)	$ 24,523
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18				
	Rounding	$ -	$ -	$ -
	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 2,412,232	$ (18,548)	$ 2,393,683

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 627	$ -	$ -	$ -	$ -	$ -	$ -	$ 627
2	Source of Supply Plant	571,108	-	-	-	-	-	-	571,108
3	Pumping Plant	951,836	-	-	-	-	-	-	951,836
4	Water Treatment Plant	104,121	-	-	-	-	-	-	104,121
5	Transmission & Distribution Plant	4,194,584	-	-	-	-	-	-	4,194,584
6	General Plant	262,652	-	-	-	-	-	-	262,652
7	Total Gross Plant in Service	$ 6,084,930	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,084,930
8	Accumulated Depreciation	(2,307,793)	(1,038)	-	-	-	-	-	(2,308,831)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 3,777,137	$ (1,038)	$ -	$ -	$ -	$ -	$ -	$ 3,776,099
10	Advances in Aid Of Const.	$ (432,749)	$ -	$ -	$ -	$ -	$ -	$ -	$ (432,749)
11	Contribution in Aid of Const.	$ (623,732)	$ -	$ -	$ -	$ -	$ -	$ -	$ (623,732)
12	Accumulated Amortization of CIAC	93,964	-	-	-	-	-	-	93,964
13	NET CIAC (L5 + L6)	$ (529,768)	$ -	$ -	$ -	$ -	$ -	$ -	$ (529,768)
14	Deferred Income Tax	$ (436,962)	$ -	$ -	$ -	$ -	$ -	$ -	$ (436,962)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (7,460)	$ -	$ (7,460)
16	Allowance for Working Capital	34,574	$ -	$ -	$ -	$ -	$ -	$ (10,051)	$ 24,523
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 2,412,232	$ (1,038)	$ -	$ -	$ -	$ (7,460)	$ (10,051)	$ 2,393,683

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Intentionally Left Blank
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 864,595	$ -	$ 864,595	$ (63,798)	$ 800,797
2	Commercial	229,443	-	229,443	-	229,443
3	Industrial	-	-	-	-	-
4	Private Fire Service	56	-	56	-	56
5	Other Water Revenues	21,015	-	21,015	-	21,015
6	Total Water Revenues	$ 1,115,109	$ -	$ 1,115,109	$ (63,798)	$ 1,051,311
7	Miscellaneous	$ 11,106	$ -	$ 11,106	$ -	$ 11,106
8	Total Operating Revenues	$ 1,126,215	$ -	$ 1,126,215	$ (63,798)	$ 1,062,417
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	9,508	-	9,508	-	9,508
11	Pumping Expenses:	-				
12	Purchased Power	149,736	-	149,736	-	149,736
13	Purchased Gas	-	-	-	-	-
14	Other	38,603	-	38,603	-	38,603
15	Water Treatment Expenses	15,542	-	15,542	-	15,542
16	Transmission & Distribution Expenses	152,010	-	152,010	-	152,010
17	Customer Accounting Expenses	100,428	-	100,428	-	100,428
18	Sales Expense	549	-	549	-	549
19	Administrative & General Expenses	151,950	(5,288)	146,662	-	146,662
20	Total Operations & Maintenance Expense	$ 618,326	$ (5,288)	$ 613,037	$ -	$ 613,037
21	Depreciation & Amortization Expenses	$ 181,393	$ (27,957)	$ 153,436	$ -	$ 153,436
	Taxes					
22	Federal Income Taxes	$ 53,978	$ 13,307	$ 67,285	$ (20,180)	$ 47,105
23	State Income Taxes	11,891	2,931	14,822	(4,445)	10,377
24	Property Taxes	53,921	(3,115)	50,806	-	50,806
25	Other	12,458	(259)	12,199	-	12,199
26	Total Taxes	$ 132,248	$ 12,864	$ 145,112	$ (24,625)	$ 120,486
27	Total Operating Expenses	$ 931,966	$ (20,381)	$ 911,585	$ (24,625)	$ 886,960
28	Operating Income	$ 194,248	$ 20,381	$ 214,630	$ (39,173)	$ 175,457

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

Arizona Water Company
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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 864,595	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 864,595
2	Commercial	229,443	-	-	-	-	-	-	-	-	-	-	229,443
3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-
4	Private Fire Service	56	-	-	-	-	-	-	-	-	-	-	56
5	Other Water Revenues	21,015	-	-	-	-	-	-	-	-	-	-	21,015
6	Total Water Revenues	$ 1,115,109	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,115,109
7	Miscellaneous	$ 11,106	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,106
8	Total Operating Revenues	$ 1,126,215	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,126,215
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	9,508	-	-	-	-	-	-	-	-	-	-	9,508
11	Pumping Expenses:												
12	Purchased Power	149,736	-	-	-	-	-	-	-	-	-	-	149,736
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	38,603	-	-	-	-	-	-	-	-	-	-	38,603
15	Water Treatment Expenses	15,542	-	-	-	-	-	-	-	-	-	-	15,542
16	Transmission & Distribution Expenses	152,010	-	-	-	-	-	-	-	-	-	-	152,010
17	Customer Accounting Expenses	100,428	-	-	-	-	-	-	-	-	-	-	100,428
18	Sales Expense	549	-	-	-	-	-	-	-	-	-	-	549
19	Administrative & General Expenses	151,950	(3,467)	-	(291)	-	-	(10)	-	-	(1,520)	-	146,662
20	Total Operations & Maintenance Expense	$ 618,326	$ (3,467)	$ -	$ (291)	$ -	$ -	$ (10)	$ -	$ -	$ (1,520)	$ -	$ 613,037
21	Depreciation & Amortization Expenses	$ 181,393	$ -	$ -	$ -	$ -	$ -	$ -	$ (27,957)	$ -	$ -	$ -	$ 153,436
	Taxes												
22	Federal Income Taxes	$ 53,978	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,307	$ 67,285
23	State Income Taxes	11,891	-	-	-	-	-	-	-	-	-	2,931	14,822
24	Property Taxes	53,921	-	-	-	-	-	-	-	(3,115)	-	-	50,806
25	Other	12,458	-	(259)	-	-	-	-	-	-	-	-	12,199
26	Total Taxes	$ 132,248	$ -	$ (259)	$ -	$ -	$ -	$ -	$ -	$ (3,115)	$ -	$ 16,238	$ 145,112
27	Total Operating Expenses	$ 931,966	$ (3,467)	$ (259)	$ (291)	$ -	$ -	$ (10)	$ (27,957)	$ (3,115)	$ (1,520)	$ 16,238	$ 911,585
28	Operating Income	$ 194,248	$ 3,467	$ 259	$ 291	$ -	$ -	$ 10	$ 27,957	$ 3,115	$ 1,520	$ (16,238)	$ 214,630

ADJUSTMENTS:	REFERENCE:
1 Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule TJC-9 Page, 1 of 3
2 Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 2 of 3
3 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 3 of 3
4 Reverse Adjustment for Conservation	Testimony WAR
5 Purchased Power Revenues	Testimony WAR
6 Insurance Expense	Testimony, WAR And Schedule TJC-10
7 Depreciation Expense	Testimony, WAR And Schedule TJC-11
8 Property Tax Expense	Testimony, WAR And Schedule TJC-12
9 Rate Case Expense	Testimony, WAR And Schedule TJC-13

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

TABLE OF CONTENTS TO TJC SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

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Winkelman System - Surrebuttal
Schedule TJC-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 325,142	$ 339,758
2	Adjusted Operating Income (Loss)	$ 10,198	$ 12,299
3	Current Rate of Return (L2 / L1)	3.14%	3.62%
4	Required Operating Income (L5 X L1)	$ 31,910	$ 24,904
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 21,712	$ 12,605
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 35,361	$ 20,529
9	Adjusted Test Year Revenue	$ 98,722	$ 98,722
10	Proposed Annual Revenue (L8 + L9)	$ 134,083	$ 119,252
11	Required Percentage Increase in Revenue (L8 / L9)	35.82%	20.80%
12	Consolidated Revenue Adjustment	$ -	$ (9,617)
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ -	$ 10,913
14	Required Revenue Under Proposed Consolidation	$ -	$ 109,635
15	Required Percentage Increase in Revenue Under Proposed Consolidation	-	11.05%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4)	$ 24,904			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2)	12,299			
13	Required Increase In Operating Income (L11 - L12)		$ 12,605		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 8,159			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	235			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 7,924		
17	Total Required Increase In Revenue (L13 + L16)		$ 20,529		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. TJC-1, Pg 1, Col. (B), L12)			$ 119,252	
19	Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23)			86,188	
20	Synchronized Interest (Col. (C), L37)			11,926	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 21,138	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 1,473
24	Fed. Taxable Income (L21 - L23)			$ 19,665	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 6,686	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 6,686
31	Combined Federal and State Income Tax (L23 + L30)				$ 8,159
32	Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23)				$ 235
33	RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23)				$ 7,924
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 339,758	
36	Weighted Avg. Cost of Debt (Sch. TJC-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 11,926	

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Winkelman System - Surrebuttal
Schedule TJC-2

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 2,137	$ -	$ 2,137
2	Source of Supply Plant	51,263	(66,360)	(15,097)
3	Pumping Plant	163,932	-	163,932
4	Water Treatment Plant	39,948	-	39,948
5	Transmission & Distribution Plant	265,881	-	265,881
6	General Plant	31,008	-	31,008
7	Total Gross Plant in Service	$ 554,169	$ (66,360)	$ 487,809
8	Accumulated Depreciation	(167,152)	82,798	(84,354)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 387,018	$ 16,438	$ 403,455
10	Advances in Aid Of Const.	$ (18,649)	$ -	$ (18,649)
11	Contribution in Aid of Const.	$ (1,835)	$ -	$ (1,835)
12	Accumulated Amortization of CIAC	506	-	506
13	NET CIAC (L5 + L6)	$ (1,329)	$ -	$ (1,329)
14	Deferred Income Tax	$ (42,163)	$ -	$ (42,163)
15	Customer Deposits	$ -	$ (650)	$ (650)
16	Allowance for Working Capital	$ 266	$ (1,171)	$ (906)
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 325,142	$ 14,616	$ 339,758

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Winkelman System - Surrebuttal
Schedule TJC-3
Page 1 of 1

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 2,137	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,137
2	Source of Supply Plant	51,263	-	-	(66,360)	-	-	-	(15,097)
3	Pumping Plant	163,932	-	-	-	-	-	-	163,932
4	Water Treatment Plant	39,948	-	-	-	-	-	-	39,948
5	Transmission & Distribution Plant	265,881	-	-	-	-	-	-	265,881
6	General Plant	31,008	-	-	-	-	-	-	31,008
7	Total Gross Plant in Service	$ 554,169	$ -	$ -	$ (66,360)	$ -	$ -	$ -	$ 487,809
8	Accumulated Depreciation	(167,152)	3,162	-	79,635	-	-	-	(84,354)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 387,018	$ 3,162	$ -	$ 13,275	$ -	$ -	$ -	$ 403,455
10	Advances in Aid Of Const.	$ (18,649)	$ -	$ -	$ -	$ -	$ -	$ -	$ (18,649)
11	Contribution in Aid of Const.	$ (1,835)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,835)
12	Accumulated Amortization of CIAC	506	-	-	-	-	-	-	506
13	NET CIAC (L5 + L6)	$ (1,329)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,329)
14	Deferred Income Tax	$ (42,163)	$ -	$ -	$ -	$ -	$ -	$ -	$ (42,163)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (650)	$ -	$ (650)
16	Allowance for Working Capital	266	$ -	$ -	$ -	$ -	$ -	$ (1,171)	$ (906)
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 325,142	$ 3,162	$ -	$ 13,275	$ -	$ (650)	$ (1,171)	$ 339,758

References:

Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 44,901	$ -	$ 44,901	$ 20,529	$ 65,430
2	Commercial	50,096	-	50,096	-	50,096
3	Industrial	1,774	-	1,774	-	1,774
4	Private Fire Service	-	-	-	-	-
5	Other Water Revenues	749	-	749	-	749
6	Total Water Revenues	$ 97,519	$ -	$ 97,519	$ 20,529	$ 118,048
7	Miscellaneous	$ 1,203	$ -	$ 1,203	$ -	$ 1,203
8	Total Operating Revenues	$ 98,722	$ -	$ 98,722	$ 20,529	$ 119,252
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	897	-	897	-	897
11	Pumping Expenses:	-				
12	Purchased Power	7,310	-	7,310	-	7,310
13	Purchased Gas	-	-	-	-	-
14	Other	4,150	-	4,150	-	4,150
15	Water Treatment Expenses	1,372	-	1,372	-	1,372
16	Transmission & Distribution Expenses	16,618	-	16,618	-	16,618
17	Customer Accounting Expenses	11,332	-	11,332	-	11,332
18	Sales Expense	58	-	58	-	58
19	Administrative & General Expenses	16,116	(506)	15,611	-	15,611
20	Total Operations & Maintenance Expense	$ 57,855	$ (506)	$ 57,349	$ -	$ 57,349
21	Depreciation & Amortization Expenses	$ 19,928	$ (2,269)	$ 17,660	$ -	$ 17,660
	Taxes					
22	Federal Income Taxes	$ (959)	$ 1,151	$ 192	$ 6,494	$ 6,686
23	State Income Taxes	(211)	254	42	1,430	1,473
24	Property Taxes	10,675	(706)	9,969	-	9,969
25	Other	1,235	(25)	1,210	-	1,210
26	Total Taxes	$ 10,741	$ 674	$ 11,414	$ 7,924	$ 19,338
27	Total Operating Expenses	$ 88,524	$ (2,101)	$ 86,423	$ 7,924	$ 94,347
28	Operating Income	$ 10,198	$ 2,101	$ 12,299	$ 12,605	$ 24,904

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 44,901	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,901
2	Commercial	50,096	-	-	-	-	-	-	-	-	-	-	50,096
3	Industrial	1,774	-	-	-	-	-	-	-	-	-	-	1,774
4	Private Fire Service	-	-	-	-	-	-	-	-	-	-	-	-
5	Other Water Revenues	749	-	-	-	-	-	-	-	-	-	-	749
6	Total Water Revenues	$ 97,519	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 97,519
7	Miscellaneous	$ 1,203	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,203
8	Total Operating Revenues	$ 98,722	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 98,722
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	897	-	-	-	-	-	-	-	-	-	-	897
11	Pumping Expenses:												
12	Purchased Power	7,310	-	-	-	-	-	-	-	-	-	-	7,310
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	4,150	-	-	-	-	-	-	-	-	-	-	4,150
15	Water Treatment Expenses	1,372	-	-	-	-	-	-	-	-	-	-	1,372
16	Transmission & Distribution Expenses	16,618	-	-	-	-	-	-	-	-	-	-	16,618
17	Customer Accounting Expenses	11,332	-	-	-	-	-	-	-	-	-	-	11,332
18	Sales Expense	58	-	-	-	-	-	-	-	-	-	-	58
19	Administrative & General Expenses	16,116	(335)	-	(28)	-	-	4	-	-	(147)	-	15,611
20	Total Operations & Maintenance Expense	$ 57,855	$ (335)	$ -	$ (28)	$ -	$ -	$ 4	$ -	$ -	$ (147)	$ -	$ 57,349
21	Depreciation & Amortization Expenses	$ 19,928	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,269)	$ -	$ -	$ -	$ 17,660
	Taxes												
22	Federal Income Taxes	$ (959)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,151	$ 192
23	State Income Taxes	(211)	-	-	-	-	-	-	-	-	-	254	42
24	Property Taxes	10,675	-	-	-	-	-	-	-	(706)	-	-	9,969
25	Other	1,235	-	(25)	-	-	-	-	-	-	-	-	1,210
26	Total Taxes	$ 10,741	$ -	$ (25)	$ -	$ -	$ -	$ -	$ -	$ (706)	$ -	$ 1,405	$ 11,414
27	Total Operating Expenses	$ 88,524	$ (335)	$ (25)	$ (28)	$ -	$ -	$ 4	$ (2,269)	$ (706)	$ (147)	$ 1,405	$ 86,423
28	Operating Income	$ 10,198	$ 335	$ 25	$ 28	$ -	$ -	$ (4)	$ 2,269	$ 706	$ 147	$ (1,405)	$ 12,299

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule TJC-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule TJC-10
7 - Depreciation Expense	Testimony, WAR And Schedule TJC-11
8 - Property Tax Expense	Testimony, WAR And Schedule TJC-12
9 - Rate Case Expense	Testimony, WAR And Schedule TJC-13
10 - Income Tax	Testimony, WAR And Schedule TJC-14

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 7,663,611	$ 7,426,481
2	Adjusted Operating Income (Loss)	$ 143,848	$ 159,794
3	Current Rate of Return (L2 / L1)	1.88%	2.15%
4	Required Operating Income (L5 X L1)	$ 752,127	$ 544,361
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 608,279	$ 384,567
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 990,665	$ 626,319
9	Adjusted Test Year Revenue	$ 1,850,677	$ 1,850,677
10	Proposed Annual Revenue (L8 + L9)	$ 2,841,341	$ 2,476,995
11	Required Percentage Increase in Revenue (L8 / L9)	53.53%	33.84%
12	Consolidated Revenue Adjustment	$ (937,341)	$ (360,458)
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ 53,500	$ 265,861
14	Required Revenue Under Proposed Consolidation	$ 1,904,272	$ 2,116,537
15	Required Percentage Increase in Revenue Under Proposed Consolidation	2.89%	14.37%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4)	$ 544,361			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2)	159,794			
13	Required Increase In Operating Income (L11 - L12)		$ 384,567		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 178,338			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	(63,414)			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 241,752		
17	Total Required Increase In Revenue (L13 + L16)		$ 626,319		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. TJC-1, Pg 1, Col. (B), L12)			$ 2,476,995	
19	Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23)			1,754,296	
20	Synchronized Interest (Col. (C), L37)			260,669	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 462,030	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 32,194
24	Fed. Taxable Income (L21 - L23)			$ 429,836	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ 6,250	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ 8,500	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ 91,650	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 32,244	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 146,144
31	Combined Federal and State Income Tax (L23 + L30)				$ 178,338
32	Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23)				$ (63,414)
33	RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23)				$ 241,752
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. TJC-2, Col. (C), L17)			$ 7,426,481	
				3.51%	
				$ 260,669	

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 2,557	$ -	$ 2,557
2	Source of Supply Plant	4,436,512	(77,542)	4,358,970
3	Pumping Plant	1,646,392	(201,695)	1,444,697
4	Water Treatment Plant	86,137	-	86,137
5	Transmission & Distribution Plant	5,281,481	-	5,281,481
6	General Plant	848,882	-	848,882
7	Total Gross Plant in Service	$ 12,301,961	$ (279,237)	$ 12,022,724
8	Accumulated Depreciation	(2,957,804)	101,814	(2,855,990)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 9,344,157	$ (177,424)	$ 9,166,733
10	Advances In Aid Of Const.	$ (12,005)	$ -	$ (12,005)
11	Contribution In Aid Of Const.	$ (324,169)	$ -	$ (324,169)
12	Accumulated Amortization Of CIAC	62,181	-	62,181
13	NET CIAC (L5 + L6)	$ (261,988)	$ -	$ (261,988)
14	Deferred Income Tax	$ (954,417)	$ -	$ (954,417)
15	Customer Deposits	$ -	$ (31,336)	$ (31,336)
16	Allowance For Working Capital	$ 79,865	$ (28,370)	$ 51,494
17	Net Regulatory Asset / (Liability)	$ (532,000)	$ -	$ (532,000)
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 7,663,611	$ (205,794)	$ 7,426,481

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 2,557	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,557
2	Source of Supply Plant	4,436,512	-	-	(77,542)	-	-	-	4,358,970
3	Pumping Plant	1,646,392	-	-	(201,695)	-	-	-	1,444,697
4	Water Treatment Plant	86,137	-	-	-	-	-	-	86,137
5	Transmission & Distribution Plant	5,281,481	-	-	-	-	-	-	5,281,481
6	General Plant	848,882	-	-	-	-	-	-	848,882
7	Total Gross Plant in Service	$ 12,301,961	$ -	$ -	$ (279,237)	$ -	$ -	$ -	$ 12,022,724
8	Accumulated Depreciation	$ (2,957,804)	25,492	-	76,321	-	-	-	(2,855,990)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 9,344,157	$ 25,492	$ -	$ (202,916)	$ -	$ -	$ -	$ 9,166,733
10	Advances In Aid Of Const.	$ (12,005)	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,005)
11	Contribution In Aid Of Const.	$ (324,169)	$ -	$ -	$ -	$ -	$ -	$ -	$ (324,169)
12	Accumulated Amortization Of CIAC	62,181	-	-	-	-	-	-	62,181
13	NET CIAC (L5 + L6)	$ (261,988)	$ -	$ -	$ -	$ -	$ -	$ -	$ (261,988)
14	Deferred Income Tax	$ (954,417)	$ -	$ -	$ -	$ -	$ -	$ -	$ (954,417)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (31,336)	$ -	$ (31,336)
16	Allowance For Working Capital	$ 79,865	$ -	$ -	$ -	$ -	$ -	$ (28,370)	$ 51,494
17	Net Regulatory Asset / (Liability)	$ (532,000)	$ -	$ -	$ -	$ -	$ -	$ -	$ (532,000)
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 7,663,611	$ 25,492	$ -	$ (202,916)	$ -	$ (31,336)	$ (28,370)	$ 7,426,481

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Miami System - Surrebuttal
Schedule TJC-7
Page 1 of 1

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 1,223,975	$ -	$ 1,223,975	$ 626,319	$ 1,850,293
2	Commercial	491,044	-	491,044	-	491,044
3	Industrial	98,160	-	98,160	-	98,160
4	Private Fire Service	874	-	874	-	874
5	Other Water Revenues	16,285	-	16,285	-	16,285
6	Total Water Revenues	$ 1,830,337	$ -	$ 1,830,337	$ 626,319	$ 2,456,655
7	Miscellaneous	$ 20,340	$ -	$ 20,340	$ -	$ 20,340
8	Total Operating Revenues	$ 1,850,677	$ -	$ 1,850,677	$ 626,319	$ 2,476,995
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	9,610	-	9,610	-	9,610
11	Pumping Expenses:					
12	Purchased Power	199,919	-	199,919	-	199,919
13	Purchased Gas	-	-	-	-	-
14	Other	106,061	-	106,061	-	106,061
15	Water Treatment Expenses	10,374	-	10,374	-	10,374
16	Transmission & Distribution Expenses	353,495	-	353,495	-	353,495
17	Customer Accounting Expenses	226,344	-	226,344	-	226,344
18	Sales Expense	2,486	-	2,486	-	2,486
19	Administrative & General Expenses	394,754	(11,549)	383,205	-	383,205
20	Total Operations & Maintenance Expense	$ 1,303,044	$ (11,549)	$ 1,291,494	$ -	$ 1,291,494
21	Depreciation & Amortization Expenses	$ 355,564	$ (18,626)	$ 336,938	$ -	$ 336,938
	Taxes					
22	Federal Income Taxes	$ (72,321)	$ 20,355	$ (51,966)	$ 198,110	$ 146,144
23	State Income Taxes	(15,932)	4,484	(11,448)	43,642	32,194
24	Property Taxes	107,575	(10,045)	97,530	-	97,530
25	Other	28,899	(566)	28,333	-	28,333
26	Total Taxes	$ 48,221	$ 14,229	$ 62,450	$ 241,752	$ 304,202
27	Total Operating Expenses	$ 1,706,829	$ (15,946)	$ 1,690,882	$ 241,752	$ 1,932,634
28	Operating Income	$ 143,848	$ 15,946	$ 159,794	$ 384,567	$ 544,361

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 1,223,975	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,223,975
2	Commercial	491,044	-	-	-	-	-	-	-	-	-	-	491,044
3	Industrial	98,160	-	-	-	-	-	-	-	-	-	-	98,160
4	Private Fire Service	874	-	-	-	-	-	-	-	-	-	-	874
5	Other Water Revenues	16,285	-	-	-	-	-	-	-	-	-	-	16,285
6	Total Water Revenues	$ 1,830,337	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,830,337
7	Miscellaneous	$ 20,340	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,340
8	Total Operating Revenues	$ 1,850,677	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,850,677
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	9,610	-	-	-	-	-	-	-	-	-	-	9,610
11	Pumping Expenses:	-	-	-	-	-			-	-	-	-	-
12	Purchased Power	199,919	-	-	-	-	-	-	-	-	-	-	199,919
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	106,061	-	-	-	-	-	-	-	-	-	-	106,061
15	Water Treatment Expenses	10,374	-	-	-	-	-	-	-	-	-	-	10,374
16	Transmission & Distribution Expenses	353,495	-	-	-	-	-	-	-	-	-	-	353,495
17	Customer Accounting Expenses	226,344	-	-	-	-	-	-	-	-	-	-	226,344
18	Sales Expense	2,486	-	-	-	-	-	-	-	-	-	-	2,486
19	Administrative & General Expenses	394,754	(7,573)	-	(636)	-	-	(20)	-	-	(3,320)	-	383,205
20	Total Operations & Maintenance Expense	$ 1,303,044	$ (7,573)	$ -	$ (636)	$ -	$ -	$ (20)	$ -	$ -	$ (3,320)	$ -	$ 1,291,494
21	Depreciation & Amortization Expenses	$ 355,564	$ -	$ -	$ -	$ -	$ -	$ -	$ (18,626)	$ -	$ -	$ -	$ 336,938
	Taxes												
22	Federal Income Taxes	$ (72,321)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,355	$ (51,966)
23	State Income Taxes	(15,932)	-	-	-	-	-	-	-	-	-	4,484	(11,448)
24	Property Taxes	107,575	-	-	-	-	-	-	-	(10,045)	-	-	97,530
25	Other	28,899	-	(566)	-	-	-	-	-	-	-	-	28,333
26	Total Taxes	$ 48,221	$ -	$ (566)	$ -	$ -	$ -	$ -	$ -	$ (10,045)	$ -	$ 24,839	$ 62,450
27	Total Operating Expenses	$ 1,706,829	$ (7,573)	$ (566)	$ (636)	$ -	$ -	$ (20)	$ (18,626)	$ (10,045)	$ (3,320)	$ 24,839	$ 1,690,882
28	Operating Income	$ 143,848	$ 7,573	$ 566	$ 636	$ -	$ -	$ 20	$ 18,626	$ 10,045	$ 3,320	$ (24,839)	$ 159,794

ADJUSTMENTS:
1 - Labor Expense - Normalize OT Hours in Test Year
2 - Payroll Tax Expense Related to Adjustment 1
3 - 401(K) Expense Related to Adjustment 1
4 - Reverse Adjustment for Conservation
5 - Purchased Power Revenues
6 - Insurance Expense
7 - Depreciation Expense
8 - Property Tax Expense
9 - Rate Case Expense

REFERENCE:
Testimony, WAR And Schedule TJC-9 Page, 1 of 3
Testimony, WAR And Schedule TJC-9 Page, 2 of 3
Testimony, WAR And Schedule TJC-9 Page, 3 of 3
Testimony WAR
Testimony WAR
Testimony, WAR And Schedule TJC-10
Testimony, WAR And Schedule TJC-11
Testimony, WAR And Schedule TJC-12
Testimony, WAR And Schedule TJC-13

Arizona Water Company
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Miami System - Surrebuttal
Schedule TJC-15

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

TABLE OF CONTENTS TO TJC SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 41,274,515	$ 39,870,486
2	Adjusted Operating Income (Loss)	$ 656,994	$ 780,941
3	Current Rate of Return (L2 / L1)	1.59%	1.96%
4	Required Operating Income (L5 X L1)	$ 4,050,790	$ 2,922,507
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 3,393,796	$ 2,141,566
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 5,527,254	$ 3,487,828
9	Adjusted Test Year Revenue	$ 10,934,895	$ 10,934,895
10	Proposed Annual Revenue (L8 + L9)	$ 16,462,148	$ 14,422,723
11	Required Percentage Increase in Revenue (L8 / L9)	50.55%	31.90%
12	Consolidated Revenue Adjustment	$ (146,842)	$ 137,287
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ 5,380,398	$ 3,625,115
14	Required Revenue Under Proposed Consolidation	$ 16,315,353	$ 14,560,010
15	Required Percentage Increase in Revenue Under Proposed Consolidation	49.20%	33.15%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-15

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4)	$ 2,922,507			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2)	780,941			
13	Required Increase In Operating Income (L11 - L12)		$ 2,141,566		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 957,444			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	(388,819)			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 1,346,263		
17	Total Required Increase In Revenue (L13 + L16)		$ 3,487,828		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. TJC-1, Pg 1, Col. (B), L12)			$ 14,422,723	
19	Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23)			10,542,772	
20	Synchronized Interest (Col. (C), L37)			1,399,454	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 2,480,496	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 172,841
24	Fed. Taxable Income (L21 - L23)			$ 2,307,655	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ 6,250	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ 8,500	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ 91,650	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 670,703	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 784,603
31	Combined Federal and State Income Tax (L23 + L30)				$ 957,444
32	Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23)				$ (388,819)
33	RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23)				$ 1,346,263
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 39,870,486	
36	Weighted Avg. Cost of Debt (Sch. TJC-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 1,399,454	

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Casa Grande System - Surrebuttal
Schedule TJC-2

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 1,975,834	$ (822,694)	$ 1,153,140
2	Source of Supply Plant	6,113,706	(896,925)	5,216,781
3	Pumping Plant	5,577,501	-	5,577,501
4	Water Treatment Plant	7,112,797	-	7,112,797
5	Transmission & Distribution Plant	80,496,004	-	80,496,004
6	General Plant	3,245,256	-	3,245,256
7	Total Gross Plant in Service	$ 104,521,097	$ (1,719,619)	$ 102,801,478
8	Accumulated Depreciation	(17,639,046)	674,867	(16,964,179)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 86,882,051	$ (1,044,752)	$ 85,837,300
10	Advances in Aid Of Const.	$ (29,671,663)	$ -	$ (29,671,663)
11	Contribution in Aid of Const.	$ (14,050,085)	$ -	$ (14,050,085)
12	Accumulated Amortization of CIAC	2,242,757	-	2,242,757
13	NET CIAC (L5 + L6)	$ (11,807,328)	$ -	$ (11,807,328)
14	Deferred Income Tax	$ (5,088,308)	$ -	$ (5,088,308)
15	Customer Deposits	$ -	$ (252,738)	$ (252,738)
16	Allowance for Working Capital	$ 383,959	$ (92,250)	$ 291,709
17	Net Regulatory Asset / (Liability)	$ 575,803	$ (14,289)	$ 561,514
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 41,274,515	$ (1,404,029)	$ 39,870,486

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Arizona Water Company
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Casa Grande System - Surrebuttal
Schedule TJC-3
Page 1 of 1

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4 REGULATORY ASSET	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
1	Plant Classification								
2	Intangible Plant	$ 1,975,834	$ (822,694)	$ -	$ -	$ -	$ -	$ -	$ 1,153,140
3	Source of Supply Plant	6,113,706	-	-	$ (896,925)	$ -	$ -	$ -	5,216,781
4	Pumping Plant	5,577,501	-	-	-	-	-	-	5,577,501
5	Water Treatment Plant	7,112,797	-	-	-	-	-	-	7,112,797
6	Transmission & Distribution Plant	80,496,004	-	-	-	-	-	-	80,496,004
7	General Plant	3,245,256	-	-	-	-	-	-	3,245,256
8	Total Gross Plant in Service	$ 104,521,097	$ (822,694)	$ -	$ (896,925)	$ -	$ -	$ -	$ 102,801,478
9	Accumulated Depreciation	(17,639,046)	(1,579)	-	-	-	-	-	(16,964,179)
10	Net Utility Plant in Service (Sum L1 & L2)	$ 86,882,051	$ (824,273)	$ -	$ (896,925)	$ -	$ -	$ -	$ 85,837,300
11	Advances in Aid Of Const.	$ (29,671,663)	$ -	$ -	676,446	-	-	-	$ (29,671,663)
12	Contribution in Aid of Const.	$ (14,050,085)	$ -	$ -	$ (220,479)	$ -	$ -	$ -	$ (14,050,085)
13	Accumulated Amortization of CIAC	2,242,757	-	-	-	-	-	-	2,242,757
14	NET CIAC (L5 + L6)	$ (11,807,328)	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,807,328)
15	Deferred Income Tax	$ (5,088,308)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,088,308)
16	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (252,738)
17	Allowance for Working Capital	383,959	$ -	$ -	$ -	$ -	$ -	$ -	$ 291,709
18	Net Regulatory Asset / (Liability)	$ 575,803	$ -	$ -	$ -	$ (252,738)	$ -	$ -	$ 561,514
19	Rounding	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 41,274,515	$ (824,273)	$ -	$ (220,479)	$ (14,289)	$ (92,250)	$ 39,870,486	

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - To Adjust Net Regulatory Asset
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 6,578,320	$ -	$ 6,578,320	$ 3,487,828	$ 10,066,148
2	Commercial	2,217,689	-	2,217,689	-	2,217,689
3	Industrial	1,085,224	-	1,085,224	-	1,085,224
4	Private Fire Service	13,268	-	13,268	-	13,268
5	Other Water Revenues	450,711	-	450,711	-	450,711
6	Total Water Revenues	$ 10,345,212	$ -	$ 10,345,212	$ 3,487,828	$ 13,833,040
7	Miscellaneous	$ 589,682	$ -	$ 589,682	$ -	$ 589,682
8	Total Operating Revenues	$ 10,934,895	$ -	$ 10,934,895	$ 3,487,828	$ 14,422,723
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ 374,207	$ -	$ 374,207	$ -	$ 374,207
10	Other	76,178	-	76,178	-	76,178
11	Pumping Expenses:	-				
12	Purchased Power	1,387,878	-	1,387,878	-	1,387,878
13	Purchased Gas	509	-	509	-	509
14	Other	537,890	-	537,890	-	537,890
15	Water Treatment Expenses	531,617	-	531,617	-	531,617
16	Transmission & Distribution Expenses	1,887,995	-	1,887,995	-	1,887,995
17	Customer Accounting Expenses	909,384	-	909,384	-	909,384
18	Sales Expense	4,312	-	4,312	-	4,312
19	Administrative & General Expenses	1,761,682	(60,564)	1,701,118	-	1,701,118
20	Total Operations & Maintenance Expense	$ 7,471,653	$ (60,564)	$ 7,411,089	$ -	$ 7,411,089
21	Depreciation & Amortization Expenses	$ 2,329,760	$ (152,308)	$ 2,177,452	$ -	$ 2,177,452
	Taxes					
22	Federal Income Taxes	$ (450,160)	$ 131,532	$ (318,628)	$ 1,103,231	$ 784,603
23	State Income Taxes	(99,166)	28,975	(70,191)	243,032	172,841
24	Property Taxes	806,467	(66,879)	739,588	-	739,588
25	Other	219,346	(4,703)	214,643	-	214,643
26	Total Taxes	$ 476,487	$ 88,925	$ 565,412	$ 1,346,263	$ 1,911,675
27	Total Operating Expenses	$ 10,277,900	$ (123,947)	$ 10,153,954	$ 1,346,263	$ 11,500,216
28	Operating Income	$ 656,994	$ 123,947	$ 780,941	$ 2,141,566	$ 2,922,507

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

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Casa Grande System - Surrebuttal
Schedule TJC-8
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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJ'D
	Operating Revenues												
1	Residential	$ 6,578,320	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,578,320
2	Commercial	2,217,689	-	-	-	-	-	-	-	-	-	-	2,217,689
3	Industrial	1,085,224	-	-	-	-	-	-	-	-	-	-	1,085,224
4	Private Fire Service	13,268	-	-	-	-	-	-	-	-	-	-	13,268
5	Other Water Revenues	450,711	-	-	-	-	-	-	-	-	-	-	450,711
6	Total Water Revenues	$ 10,345,212	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,345,212
7	Miscellaneous	$ 589,682	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 589,682
8	Total Operating Revenues	$ 10,934,895	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,934,895
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ 374,207	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 374,207
10	Other	76,178	-	-	-	-	-	-	-	-	-	-	76,178
11	Pumping Expenses:												
12	Purchased Power	1,387,878	-	-	-	-	-	-	-	-	-	-	1,387,878
13	Purchased Gas	509	-	-	-	-	-	-	-	-	-	-	509
14	Other	537,890	-	-	-	-	-	-	-	-	-	-	537,890
15	Water Treatment Expenses	531,617	-	-	-	-	-	-	-	-	-	-	531,617
16	Transmission & Distribution Expenses	1,887,995	-	-	-	-	-	-	-	-	-	-	1,887,995
17	Customer Accounting Expenses	909,384	-	-	-	-	-	-	-	-	-	-	909,384
18	Sales Expense	4,312	-	-	-	-	-	-	-	-	-	-	4,312
19	Administrative & General Expenses	1,761,882	(40,375)	-	(3,412)	-	-	(149)	-	-	(16,627)	-	1,701,119
20	Total Operations & Maintenance Expense	$ 7,471,653	$ (40,375)	$ -	$ (3,412)	$ -	$ -	$ (149)	$ -	$ -	$ (16,627)	$ -	$ 7,411,089
21	Depreciation & Amortization Expenses	$ 2,329,760	$ -	$ -	$ -	$ -	$ -	$ -	$ (152,308)	$ -	$ -	$ -	$ 2,177,452
	Taxes												
22	Federal Income Taxes	$ (450,160)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 131,532	$ (318,628)
23	State Income Taxes	(99,166)	-	-	-	-	-	-	-	-	-	28,975	(70,191)
24	Property Taxes	806,467	-	-	-	-	-	(149)	-	(66,730)	-	-	739,588
25	Other	219,346	-	(4,703)	-	-	-	-	-	-	-	-	214,643
26	Total Taxes	$ 476,487	$ -	$ (4,703)	$ -	$ -	$ -	$ (149)	$ -	$ (66,730)	$ -	$ 160,507	$ 565,412
27	Total Operating Expenses	$ 10,277,900	$ (40,375)	$ (4,703)	$ (3,412)	$ -	$ -	$ (299)	$ (152,308)	$ (66,730)	$ (16,627)	$ 160,507	$ 10,153,954
28	Operating Income	$ 656,994	$ 40,375	$ 4,703	$ 3,412	$ -	$ -	$ 299	$ 152,308	$ 66,730	$ 16,627	$ (160,507)	$ 780,941

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule TJC-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule TJC-10
7 - Depreciation Expense	Testimony, WAR And Schedule TJC-11
8 - Property Tax Expense	Testimony, WAR And Schedule TJC-12
9 - Rate Case Expense	Testimony, WAR And Schedule TJC-13
10 - Income Tax	Testimony, WAR And Schedule TJC-14

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

TABLE OF CONTENTS TO TJC SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 823,590	$ 781,962
2	Adjusted Operating Income (Loss)	$ (31,092)	$ (30,967)
3	Current Rate of Return (L2 / L1)	-3.78%	-3.96%
4	Required Operating Income (L5 X L1)	$ 80,829	$ 57,318
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 111,922	$ 88,285
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 182,279	$ 143,784
9	Adjusted Test Year Revenue	$ 131,926	$ 131,926
10	Proposed Annual Revenue (L8 + L9)	$ 314,205	$ 275,710
11	Required Percentage Increase in Revenue (L8 / L9)	138.17%	108.99%
12	Consolidated Revenue Adjustment	$ (174,589)	$ (120,609)
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ 7,690	$ 23,175
14	Required Revenue Under Proposed Consolidation	$ 139,662	$ 155,101
15	Required Percentage Increase in Revenue Under Proposed Consolidation	5.85%	17.57%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-15

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4)	$ 57,318			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2)	(30,967)			
13	Required Increase In Operating Income (L11 - L12)		$ 88,285		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 18,778			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	(36,721)			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 55,499		
17	Total Required Increase In Revenue (L13 + L16)		$ 143,784		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. TJC-1, Pg 1, Col. (B), L12)			$ 275,710	
19	Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23)			199,614	
20	Synchronized Interest (Col. (C), L37)			27,447	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 48,649	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 3,390
24	Fed. Taxable Income (L21 - L23)			$ 45,259	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 15,388	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 15,388
31	Combined Federal and State Income Tax (L23 + L30)				$ 18,778
32	Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23)				$ (36,721)
33	RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23)				$ 55,499
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 781,962	
36	Weighted Avg. Cost of Debt (Sch. TJC-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 27,447	

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 1,223	$ -	$ 1,223
2	Source of Supply Plant	172,909	-	172,909
3	Pumping Plant	428,386	(2,500)	425,886
4	Water Treatment Plant	32,783	(35,041)	(2,258)
5	Transmission & Distribution Plant	438,789	(5,100)	433,689
6	General Plant	106,655	-	106,655
7	Total Gross Plant in Service	$ 1,180,745	$ (42,641)	$ 1,138,104
8	Accumulated Depreciation	(260,401)	7,385	(253,016)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 920,344	$ (35,256)	$ 885,088
10	Advances in Aid Of Const.	$ (15,715)	$ -	$ (15,715)
11	Contribution in Aid of Const.	$ (49,164)	$ -	$ (49,164)
12	Accumulated Amortization of CIAC	12,246	-	12,246
13	NET CIAC (L5 + L6)	$ (36,918)	$ -	$ (36,918)
14	Deferred Income Tax	$ (51,746)	$ -	$ (51,746)
15	Customer Deposits	$ -	$ (2,635)	$ (2,635)
16	Allowance for Working Capital	$ 7,625	$ (3,738)	$ 3,887
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 823,590	$ (41,628)	$ 781,962

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Stanfield System - Surrebuttal
Schedule TJC-3

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 1,223	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,223
2	Source of Supply Plant	172,909	-	-	-	-	-	-	172,909
3	Pumping Plant	428,386	-	-	(2,500)	-	-	-	425,886
4	Water Treatment Plant	32,783	-	-	(35,041)	-	-	-	(2,258)
5	Transmission & Distribution Plant	438,789	-	-	(5,100)	-	-	-	433,689
6	General Plant	106,655	-	-	-	-	-	-	106,655
7	Total Gross Plant in Service	$ 1,180,745	$ -	$ -	$ (42,641)	$ -	$ -	$ -	$ 1,138,104
8	Accumulated Depreciation	(260,401)	(9,692)	-	17,077	-	-	-	(253,016)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 920,344	$ (9,692)	$ -	$ (25,564)	$ -	$ -	$ -	$ 885,088
10	Advances in Aid Of Const.	$ (15,715)	$ -	$ -	$ -	$ -	$ -	$ -	$ (15,715)
11	Contribution in Aid of Const.	$ (49,164)	$ -	$ -	$ -	$ -	$ -	$ -	$ (49,164)
12	Accumulated Amortization of CIAC	12,246		-	-	-	-	-	12,246
13	NET CIAC (L5 + L6)	$ (36,918)	$ -	$ -	$ -	$ -	$ -	$ -	$ (36,918)
14	Deferred Income Tax	$ (51,746)	$ -	$ -	$ -	$ -	$ -	$ -	$ (51,746)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (2,635)	$ -	$ (2,635)
16	Allowance for Working Capital	7,625	$ -	$ -	$ -	$ -	$ -	$ (3,738)	$ 3,887
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 823,590	$ (9,692)	$ -	$ (25,564)	$ -	$ (2,635)	$ (3,738)	$ 781,962

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Stanfield System - Surrebuttal
Schedule TJC-7
Page 1 of 1

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 88,841	$ -	$ 88,841	$ 143,784	$ 232,624
2	Commercial	22,651	-	22,651	$ -	22,651
3	Industrial	-	-	-	$ -	-
4	Private Fire Service	-	-	-	$ -	-
5	Other Water Revenues	19,498	-	19,498	$ -	19,498
6	Total Water Revenues	$ 130,990	$ -	$ 130,990	$ 143,784	$ 274,774
7	Miscellaneous	$ 936	$ -	$ 936	$ -	$ 936
8	Total Operating Revenues	$ 131,926	$ -	$ 131,926	$ 143,784	$ 275,710
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	378	-	378	-	378
11	Pumping Expenses:	-				
12	Purchased Power	20,599	-	20,599	-	20,599
13	Purchased Gas	-	-	-	-	-
14	Other	4,831	-	4,831	-	4,831
15	Water Treatment Expenses	62,986	-	62,986	-	62,986
16	Transmission & Distribution Expenses	25,008	-	25,008	-	25,008
17	Customer Accounting Expenses	8,718	-	8,718	-	8,718
18	Sales Expense	43	-	43	-	43
19	Administrative & General Expenses	17,560	(627)	16,934	-	16,934
20	Total Operations & Maintenance Expense	$ 140,124	$ (627)	$ 139,498	$ -	$ 139,498
21	Depreciation & Amortization Expenses	$ 46,067	$ (1,478)	$ 44,589	$ -	$ 44,589
	Taxes					
22	Federal Income Taxes	$ (31,753)	$ 1,661	$ (30,092)	$ 45,480	$ 15,388
23	State Income Taxes	(6,995)	366	(6,629)	10,019	3,390
24	Property Taxes	14,053	-	14,053	-	14,053
25	Other	1,522	(48)	1,474	-	1,474
26	Total Taxes	$ (23,173)	$ 1,979	$ (21,194)	$ 55,499	$ 34,305
27	Total Operating Expenses	$ 163,018	$ (125)	$ 162,893	$ 55,499	$ 218,392
28	Operating Income	$ (31,092)	$ 125	$ (30,967)	$ 88,285	$ 57,318

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 88,841	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 88,841
2	Commercial	22,651	-	-	-	-	-	-	-	-	-	-	22,651
3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-
4	Private Fire Service	-	-	-	-	-	-	-	-	-	-	-	-
5	Other Water Revenues	19,498	-	-	-	-	-	-	-	-	-	-	19,498
6	Total Water Revenues	$ 130,990	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 130,990
7	Miscellaneous	$ 936	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 936
8	Total Operating Revenues	$ 131,926	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 131,926
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	378	-	-	-	-	-	-	-	-	-	-	378
11	Pumping Expenses:												
12	Purchased Power	20,599	-	-	-	-	-	-	-	-	-	-	20,599
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	4,831	-	-	-	-	-	-	-	-	-	-	4,831
15	Water Treatment Expenses	62,986	-	-	-	-	-	-	-	-	-	-	62,986
16	Transmission & Distribution Expenses	25,008	-	-	-	-	-	-	-	-	-	-	25,008
17	Customer Accounting Expenses	8,718	-	-	-	-	-	-	-	-	-	-	8,718
18	Sales Expense	43	-	-	-	-	-	-	-	-	-	-	43
19	Administrative & General Expenses	17,560	(411)	-	(35)	-	-	(1)	-	-	(180)	-	16,934
20	Total Operations & Maintenance Expense	$ 140,124	$ (411)	$ -	$ (35)	$ -	$ -	$ (1)	$ -	$ -	$ (180)	$ -	$ 139,498
21	Depreciation & Amortization Expenses	$ 46,067	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,478)	$ -	$ -	$ -	$ 44,589
	Taxes												
22	Federal Income Taxes	$ (31,753)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,661	$ (30,092)
23	State Income Taxes	(6,995)	-	-	-	-	-	-	-	-	-	366	(6,629)
24	Property Taxes	14,053	-	-	-	-	-	-	-	-	-	-	14,053
25	Other	1,522	-	(48)	-	-	-	-	-	-	-	-	1,474
26	Total Taxes	$ (23,173)	$ -	$ (48)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,027	$ (21,194)
27	Total Operating Expenses	$ 163,018	$ (411)	$ (48)	$ (35)	$ -	$ -	$ (1)	$ (1,478)	$ -	$ (180)	$ 2,027	$ 162,893
28	Operating Income	$ (31,092)	$ 411	$ 48	$ 35	$ -	$ -	$ 1	$ 1,478	$ -	$ 180	$ (2,027)	$ (30,967)

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule TJC-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule TJC-10
7 - Depreciation Expense	Testimony, WAR And Schedule TJC-11
8 - Property Tax Expense	Testimony, WAR And Schedule TJC-12
9 - Rate Case Expense	Testimony, WAR And Schedule TJC-13
10 Income Tax	Testimony, WAR And Schedule TJC-14

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

TABLE OF CONTENTS TO TJC SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

Arizona Water Company
Docket Nos. W-01445A-08-0440
Test Year Ended December 31, 2007

White Tank System - Surrebuttal
Schedule TJC-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 4,415,017	$ 4,334,611
2	Adjusted Operating Income (Loss)	$ 130,069	$ 131,942
3	Current Rate of Return (L2 / L1)	2.95%	3.04%
4	Required Operating Income (L5 X L1)	$ 433,301	$ 317,727
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 303,233	$ 185,785
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 493,855	$ 302,576
9	Adjusted Test Year Revenue	$ 1,244,735	$ 1,244,735
10	Proposed Annual Revenue (L8 + L9)	$ 1,739,054	$ 1,547,311
11	Required Percentage Increase in Revenue (L8 / L9)	39.68%	24.31%
12	Consolidated Revenue Adjustment	$ -	$ 10,210
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ -	$ 312,786
14	Required Revenue Under Proposed Consolidation	$ -	$ 1,557,521
15	Required Percentage Increase in Revenue Under Proposed Consolidation	-	25.13%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-15

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4)	$ 317,727			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2)	131,942			
13	Required Increase In Operating Income (L11 - L12)		$ 185,785		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 104,091			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	(12,700)			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 116,791		
17	Total Required Increase In Revenue (L13 + L16)		$ 302,576		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. TJC-1, Pg 1, Col. (B), L12)			$ 1,547,311	
19	Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23)			1,125,493	
20	Synchronized Interest (Col. (C), L37)			152,145	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 269,673	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 18,791
24	Fed. Taxable Income (L21 - L23)			$ 250,882	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 85,300	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 85,300
31	Combined Federal and State Income Tax (L23 + L30)				$ 104,091
32	Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23)				$ (12,700)
33	RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23)				$ 116,791
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 4,334,611	
36	Weighted Avg. Cost of Debt (Sch. TJC-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 152,145	

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 10,580	$ -	$ 10,580
2	Source of Supply Plant	615,238	-	615,238
3	Pumping Plant	881,883	(35,104)	846,779
4	Water Treatment Plant	1,119,829	(904)	1,118,925
5	Transmission & Distribution Plant	10,239,592	-	10,239,592
6	General Plant	269,914	-	269,914
7	Total Gross Plant in Service	$ 13,137,036	$ (36,008)	$ 13,101,028
8	Accumulated Depreciation	(1,716,046)	27,545	(1,688,502)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 11,420,990	$ (8,463)	$ 11,412,526
10	Advances in Aid Of Const.	$ (5,647,808)	$ -	$ (5,647,808)
11	Contribution in Aid of Const.	$ (1,134,727)	$ -	$ (1,134,727)
12	Accumulated Amortization of CIAC	175,250	-	175,250
13	NET CIAC (L5 + L6)	$ (959,477)	$ -	$ (959,477)
14	Deferred Income Tax	$ (454,211)	$ -	$ (454,211)
15	Customer Deposits	$ 55,523	$ (9,530)	$ 45,993
16	Allowance for Working Capital	$ 55,523	$ (71,942)	$ (16,420)
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 4,415,017	$ (80,406)	$ 4,334,611

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Arizona Water Company
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White Tank System - Surrebuttal
Schedule TJC-3

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 10,580	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,580
2	Source of Supply Plant	615,238	-	-	-	-	-	-	615,238
3	Pumping Plant	881,883	-	-	(35,104)	-	-	-	846,779
4	Water Treatment Plant	1,119,829	-	-	(904)	-	-	-	1,118,925
5	Transmission & Distribution Plant	10,239,592	-	-	-	-	-	-	10,239,592
6	General Plant	269,914	-	-	-	-	-	-	269,914
7	Total Gross Plant in Service	$ 13,137,036	$ -	$ -	$ (36,008)	$ -	$ -	$ -	$ 13,101,028
8	Accumulated Depreciation	(1,716,046)	54	-	27,491	-	-	-	(1,688,502)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 11,420,990	$ 54	$ -	$ (8,517)	$ -	$ -	$ -	$ 11,412,526
10	Advances in Aid Of Const.	$ (5,647,808)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,647,808)
11	Contribution in Aid of Const.	$ (1,134,727)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,134,727)
12	Accumulated Amortization of CIAC	175,250	-	-	-	-	-	-	175,250
13	NET CIAC (L5 + L6)	$ (959,477)	$ -	$ -	$ -	$ -	$ -	$ -	$ (959,477)
14	Deferred Income Tax	$ (454,211)	$ -	$ -	$ -	$ -	$ -	$ -	$ (454,211)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (9,530)	$ -	$ (9,530)
16	Allowance for Working Capital	$ 55,523	$ -	$ -	$ -	$ -	$ -	$ (71,942)	$ (16,420)
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 4,415,017	$ 54	$ -	$ (8,517)	$ -	$ -	$ (71,942)	$ 4,334,611

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
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White Tank System - Surrebuttal
Schedule TJC-7

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 1,057,928	$ -	$ 1,057,928	$ 302,576	$ 1,360,504
2	Commercial	119,358	-	119,358	-	119,358
3	Industrial	18,658	-	18,658	-	18,658
4	Private Fire Service	295	-	295	-	295
5	Other Water Revenues	36,166	-	36,166	-	36,166
6	Total Water Revenues	$ 1,232,404	$ -	$ 1,232,404	$ 302,576	$ 1,534,980
7	Miscellaneous	$ 12,331	$ -	$ 12,331	$ -	$ 12,331
8	Total Operating Revenues	$ 1,244,735	$ -	$ 1,244,735	$ 302,576	$ 1,547,311
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ 150,244	$ -	$ 150,244	$ -	$ 150,244
10	Other	5,606	-	5,606	-	5,606
11	Pumping Expenses:	-				
12	Purchased Power	105,581	-	105,581	-	105,581
13	Purchased Gas	-	-	-	-	-
14	Other	41,276	-	41,276	-	41,276
15	Water Treatment Expenses	34,975	-	34,975	-	34,975
16	Transmission & Distribution Expenses	173,577	-	173,577	-	173,577
17	Customer Accounting Expenses	72,619	-	72,619	-	72,619
18	Sales Expense	362	-	362	-	362
19	Administrative & General Expenses	146,701	(5,500)	141,201	-	141,201
20	Total Operations & Maintenance Expense	$ 730,940	$ (5,500)	$ 725,440	$ -	$ 725,440
21	Depreciation & Amortization Expenses	$ 294,495	$ (3,953)	$ 290,542	$ -	$ 290,542
	Taxes					
22	Federal Income Taxes	$ (17,350)	$ 6,943	$ (10,408)	$ 95,707	$ 85,300
23	State Income Taxes	(3,822)	1,529	(2,293)	21,083	18,791
24	Property Taxes	53,436	(473)	52,963	-	52,963
25	Other	56,967	(420)	56,547	-	56,547
26	Total Taxes	$ 89,231	$ 7,579	$ 96,811	$ 116,791	$ 213,601
27	Total Operating Expenses	$ 1,114,666	$ (1,873)	$ 1,112,793	$ 116,791	$ 1,229,584
28	Operating Income	$ 130,069	$ 1,873	$ 131,942	$ 185,785	$ 317,727

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

Arizona Water Company
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Test Year Ended December 31, 2007

White Tank System - Surrebuttal
Schedule TJC-8

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 1,057,928	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,057,928
2	Commercial	119,358	-	-	-	-	-	-	-	-	-	-	119,358
3	Industrial	18,658	-	-	-	-	-	-	-	-	-	-	18,658
4	Private Fire Service	295	-	-	-	-	-	-	-	-	-	-	295
5	Other Water Revenues	36,166	-	-	-	-	-	-	-	-	-	-	36,166
6	Total Water Revenues	$ 1,232,404	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,232,404
7	Miscellaneous	$ 12,331	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,331
8	Total Operating Revenues	$ 1,244,735	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,244,735
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ 150,244	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 150,244
10	Other	5,606	-	-	-	-	-	-	-	-	-	-	5,606
11	Pumping Expenses:												
12	Purchased Power	105,581	-	-	-	-	-	-	-	-	-	-	105,581
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	41,276	-	-	-	-	-	-	-	-	-	-	41,276
15	Water Treatment Expenses	34,975	-	-	-	-	-	-	-	-	-	-	34,975
16	Transmission & Distribution Expenses	173,577	-	-	-	-	-	-	-	-	-	-	173,577
17	Customer Accounting Expenses	72,619	-	-	-	-	-	-	-	-	-	-	72,619
18	Sales Expense	362	-	-	-	-	-	-	-	-	-	-	362
19	Administrative & General Expenses	146,701	(3,604)	-	(305)	-	-	(11)	-	-	(1,580)	-	141,201
20	Total Operations & Maintenance Expense	$ 730,940	$ (3,604)	$ -	$ (305)	$ -	$ -	$ (11)	$ -	$ -	$ (1,580)	$ -	$ 725,440
21	Depreciation & Amortization Expenses	$ 294,495	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,953)	$ -	$ -	$ -	$ 290,542
	Taxes												
22	Federal Income Taxes	$ (17,350)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,943	$ (10,408)
23	State Income Taxes	(3,822)	-	-	-	-	-	-	-	-	-	1,529	(2,293)
24	Property Taxes	53,436	-	-	-	-	-	-	-	(473)	-	-	52,963
25	Other	56,967	-	(420)	-	-	-	-	-	-	-	-	56,547
26	Total Taxes	$ 89,231	$ -	$ (420)	$ -	$ -	$ -	$ -	$ -	$ (473)	$ -	$ 8,472	$ 96,811
27	Total Operating Expenses	$ 1,114,666	$ (3,604)	$ (420)	$ (305)	$ -	$ -	$ (11)	$ (3,953)	$ (473)	$ (1,580)	$ 8,472	$ 1,112,793
28	Operating Income	$ 130,069	$ 3,604	$ 420	$ 305	$ -	$ -	$ 11	$ 3,953	$ 473	$ 1,580	$ (8,472)	$ 131,942

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule TJC-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule TJC-10
7 - Depreciation Expense	Testimony, WAR And Schedule TJC-11
8 - Property Tax Expense	Testimony, WAR And Schedule TJC-12
9 - Rate Case Expense	Testimony, WAR And Schedule TJC-13
10 - Income Tax	Testimony, WAR And Schedule TJC-14

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

TABLE OF CONTENTS TO TJC SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

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Ajo System - Surrebuttal
Schedule TJC-1
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REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 1,123,706	$ 1,097,935
2	Adjusted Operating Income (Loss)	$ 49,548	$ 51,013
3	Current Rate of Return (L2 / L1)	4.41%	4.65%
4	Required Operating Income (L5 X L1)	$ 110,284	$ 80,479
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 60,735	$ 29,466
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 98,916	$ 47,989
9	Adjusted Test Year Revenue	$ 470,994	$ 470,994
10	Proposed Annual Revenue (L8 + L9)	$ 569,955	$ 518,982
11	Required Percentage Increase in Revenue (L8 / L9)	20.99%	10.19%
12	Consolidated Revenue Adjustment	$ -	$ 3,676
13	Required Incease in Gross Revenue Under Proposed Consolidation	$ -	$ 51,665
14	Required Revenue Under Proposed Consolidation	$ -	$ 522,659
15	Required Percentage Increase in Revenue Under Proposed Consolidation	-	10.97%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-15

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4)	$ 80,479			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2)	51,013			
13	Required Increase In Operating Income (L11 - L12)		$ 29,466		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 26,366			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	7,843			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 18,523		
17	Total Required Increase In Revenue (L13 + L16)		$ 47,989		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. TJC-1, Pg 1, Col. (B), L12)			$ 518,982	
19	Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23)			412,138	
20	Synchronized Interest (Col. (C), L37)			38,538	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 68,307	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 4,760
24	Fed. Taxable Income (L21 - L23)			$ 63,547	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 21,606	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 21,606
31	Combined Federal and State Income Tax (L23 + L30)				$ 26,366
32	Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23)				$ 7,843
33	RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23)				$ 18,523
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 1,097,935	
36	Weighted Avg. Cost of Debt (Sch. TJC-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 38,538	

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Schedule TJC-2
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RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 3,702	$ -	$ 3,702
2	Source of Supply Plant	9,477	-	9,477
3	Pumping Plant	89,231	-	89,231
4	Water Treatment Plant	4,306	-	4,306
5	Transmission & Distribution Plant	1,916,378	-	1,916,378
6	General Plant	184,119	-	184,119
7	Total Gross Plant in Service	$ 2,207,212	$ -	$ 2,207,212
8	Accumulated Depreciation	(812,825)	(13)	(812,838)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 1,394,387	$ (13)	$ 1,394,375
10	Advances in Aid Of Const.	$ (87,953)	$ -	$ (87,953)
11	Contribution in Aid of Const.	$ (65,554)	$ -	$ (65,554)
12	Accumulated Amortization of CIAC	15,854	-	15,854
13	NET CIAC (L5 + L6)	$ (49,700)	$ -	$ (49,700)
14	Deferred Income Tax	$ (155,237)	$ -	$ (155,237)
15	Customer Deposits	$ -	$ (4,600)	$ (4,600)
16	Allowance for Working Capital	$ 22,208	$ (21,159)	$ 1,050
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 1,123,706	$ (25,771)	$ 1,097,935

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 3,702	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,702
2	Source of Supply Plant	9,477	-	-	-	-	-	-	9,477
3	Pumping Plant	89,231	-	-	-	-	-	-	89,231
4	Water Treatment Plant	4,306	-	-	-	-	-	-	4,306
5	Transmission & Distribution Plant	1,916,378	-	-	-	-	-	-	1,916,378
6	General Plant	184,119	-	-	-	-	-	-	184,119
7	Total Gross Plant in Service	$ 2,207,212	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,207,212
8	Accumulated Depreciation	(812,825)	(13)	-	-	-	-	-	(812,838)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 1,394,387	$ (13)	$ -	$ -	$ -	$ -	$ -	$ 1,394,375
10	Advances in Aid Of Const.	$ (87,953)	$ -	$ -	$ -	$ -	$ -	$ -	$ (87,953)
11	Contribution in Aid of Const.	$ (65,554)	$ -	$ -	$ -	$ -	$ -	$ -	$ (65,554)
12	Accumulated Amortization of CIAC	15,854	-	-	-	-	-	-	15,854
13	NET CIAC (L5 + L6)	$ (49,700)	$ -	$ -	$ -	$ -	$ -	$ -	$ (49,700)
14	Deferred Income Tax	$ (155,237)	$ -	$ -	$ -	$ -	$ -	$ -	$ (155,237)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (4,600)	$ -	$ (4,600)
16	Allowance for Working Capital	22,208	$ -	$ -	$ -	$ -	$ -	$ (21,159)	$ 1,050
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 1,123,706	$ (13)	$ -	$ -	$ -	$ (4,600)	$ (21,159)	$ 1,097,935

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

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OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 360,038	$ -	$ 360,038	$ 47,989	$ 408,027
2	Commercial	106,351	-	106,351	-	106,351
3	Industrial	-	-	-	-	-
4	Private Fire Service	124	-	124	-	124
5	Other Water Revenues	812	-	812	-	812
6	Total Water Revenues	$ 467,325	$ -	$ 467,325	$ 47,989	$ 515,314
7	Miscellaneous	$ 3,669	$ -	$ 3,669	$ -	$ 3,669
8	Total Operating Revenues	$ 470,994	$ -	$ 470,994	$ 47,989	$ 518,982
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ 159,092	$ -	$ 159,092	$ -	$ 159,092
10	Other	71	-	71	-	71
11	Pumping Expenses:	-				
12	Purchased Power	3,297	-	3,297	-	3,297
13	Purchased Gas	-	-	-	-	-
14	Other	16,314	-	16,314	-	16,314
15	Water Treatment Expenses	4,904	-	4,904	-	4,904
16	Transmission & Distribution Expenses	66,320	-	66,320	-	66,320
17	Customer Accounting Expenses	29,076	-	29,076	-	29,076
18	Sales Expense	133	-	133	-	133
19	Administrative & General Expenses	55,525	(1,880)	53,644	-	53,644
20	Total Operations & Maintenance Expense	$ 334,732	$ (1,880)	$ 332,851	$ -	$ 332,851
21	Depreciation & Amortization Expenses	$ 51,154	$ (706)	$ 50,448	$ -	$ 50,448
	Taxes					
22	Federal Income Taxes	$ 4,055	$ 2,372	$ 6,427	$ 15,179	$ 21,606
23	State Income Taxes	893	523	1,416	3,344	4,760
24	Property Taxes	26,265	(1,630)	24,636	-	24,636
25	Other	4,347	(143)	4,203	-	4,203
26	Total Taxes	$ 35,560	$ 1,122	$ 36,681	$ 18,523	$ 55,205
27	Total Operating Expenses	$ 421,445	$ (1,465)	$ 419,981	$ 18,523	$ 438,504
28	Operating Income	$ 49,548	$ 1,465	$ 51,013	$ 29,466	$ 80,479

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

Arizona Water Company
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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 360,038	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 360,038
2	Commercial	106,351	-	-	-	-	-	-	-	-	-	-	106,351
3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-
4	Private Fire Service	124	-	-	-	-	-	-	-	-	-	-	124
5	Other Water Revenues	812	-	-	-	-	-	-	-	-	-	-	812
6	Total Water Revenues	$ 467,325	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 467,325
7	Miscellaneous	$ 3,669	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,669
8	Total Operating Revenues	$ 470,994	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 470,994
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ 159,092	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 159,092
10	Other	71	-	-	-	-	-	-	-	-	-	-	71
11	Pumping Expenses:												
12	Purchased Power	3,297	-	-	-	-	-	-	-	-	-	-	3,297
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	16,314	-	-	-	-	-	-	-	-	-	-	16,314
15	Water Treatment Expenses	4,904	-	-	-	-	-	-	-	-	-	-	4,904
16	Transmission & Distribution Expenses	66,320	-	-	-	-	-	-	-	-	-	-	66,320
17	Customer Accounting Expenses	29,076	-	-	-	-	-	-	-	-	-	-	29,076
18	Sales Expense	133	-	-	-	-	-	-	-	-	-	-	133
19	Administrative & General Expenses	55,525	(1,232)	-	(104)	-	-	(4)	-	-	(540)	-	53,644
20	Total Operations & Maintenance Expense	$ 334,732	$ (1,232)	$ -	$ (104)	$ -	$ -	$ (4)	$ -	$ -	$ (540)	$ -	$ 332,851
21	Depreciation & Amortization Expenses	$ 51,154	$ -	$ -	$ -	$ -	$ -	$ -	$ (706)	$ -	$ -	$ -	$ 50,448
	Taxes												
22	Federal Income Taxes	$ 4,055	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,372	$ 6,427
23	State Income Taxes	893	-	-	-	-	-	-	-	-	-	523	1,416
24	Property Taxes	26,265	-	-	-	-	-	-	-	(1,630)	-	-	24,636
25	Other	4,347	-	(143)	-	-	-	-	-	-	-	-	4,203
26	Total Taxes	$ 35,560	$ -	$ (143)	$ -	$ -	$ -	$ -	$ -	$ (1,630)	$ -	$ 2,895	$ 36,681
27	Total Operating Expenses	$ 421,445	$ (1,232)	$ (143)	$ (104)	$ -	$ -	$ (4)	$ (706)	$ (1,630)	$ (540)	$ 2,895	$ 419,981
28	Operating Income	$ 49,548	$ 1,232	$ 143	$ 104	$ -	$ -	$ 4	$ 706	$ 1,630	$ 540	$ (2,895)	$ 51,013

ADJUSTMENTS:
1 - Labor Expense - Normalize OT Hours in Test Year
2 - Payroll Tax Expense Related to Adjustment 1
3 - 401(K) Expense Related to Adjustment 1
4 - Reverse Adjustment for Conservation
5 - Purchased Power Revenues
6 - Insurance Expense
7 - Depreciation Expense
8 - Property Tax Expense
9 - Rate Case Expense
10 - Income Tax

REFERENCE:
Testimony, WAR And Schedule TJC-8 Page, 1 of 3
Testimony, WAR And Schedule TJC-8 Page, 2 of 3
Testimony, WAR And Schedule TJC-8 Page, 3 of 3
Testimony WAR
Testimony WAR
Testimony, WAR And Schedule TJC-10
Testimony, WAR And Schedule TJC-11
Testimony, WAR And Schedule TJC-12
Testimony, WAR And Schedule TJC-13
Testimony, WAR And Schedule TJC-14

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Schedule TJC-15

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

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Coolidge System - Surrebuttal
Schedule TJC-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 4,318,206	$ 3,433,064
2	Adjusted Operating Income (Loss)	$ 276,633	$ 295,500
3	Current Rate of Return (L2 / L1)	6.41%	8.61%
4	Required Operating Income (L5 X L1)	$ 423,800	$ 251,644
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 147,168	$ (43,857)
7	Gross Revenue Conversion Factor (TJC-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 239,682	$ (71,427)
9	Adjusted Test Year Revenue	$ 2,214,952	$ 2,214,952
10	Proposed Annual Revenue (L8 + L9)	$ 2,454,634	$ 2,143,525
11	Required Percentage Increase in Revenue (L8 / L9)	10.82%	-3.22%
12	Consolidated Revenue Adjustment	$ 321,431	$ 29,664
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ 561,113	$ (41,763)
14	Required Revenue Under Proposed Consolidation	$ 2,776,111	$ 2,173,189
15	Required Percentage Increase in Revenue Under Proposed Consolidation	25.34%	-1.89%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-7, and TJC-15

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4)	$ 251,644			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2)	295,500			
13	Required Increase In Operating Income (L11 - L12)		$ (43,857)		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 82,441			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	110,011			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ (27,570)		
17	Total Required Increase In Revenue (L13 + L16)		$ (71,427)		
	CALCULATION OF INCOME TAX			RUCO Recommended	
18	Revenue (Sch. TJC-1, Pg 1, Col. (B), L12)			$ 2,143,525	
19	Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23)			1,809,440	
20	Synchronized Interest (Col. (C), L37)			120,501	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 213,584	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 14,883
24	Fed. Taxable Income (L21 - L23)			$ 198,702	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 67,559	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 67,559
31	Combined Federal and State Income Tax (L23 + L30)				$ 82,441
32	Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23)				$ 110,011
33	RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23)				$ (27,570)
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 3,433,064	
36	Weighted Avg. Cost of Debt (Sch. TJC-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 120,501	

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RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 42,011	$ -	$ 42,011
2	Source of Supply Plant	2,098,977	(856,324)	1,242,653
3	Pumping Plant	1,400,953	-	1,400,953
4	Water Treatment Plant	845,417	-	845,417
5	Transmission & Distribution Plant	11,910,083	-	11,910,083
6	General Plant	762,698	-	762,698
7	Total Gross Plant in Service	$ 17,060,139	$ (856,324)	$ 16,203,815
8	Accumulated Depreciation	(3,207,118)	51,770	(3,155,348)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 13,853,022	$ (804,554)	$ 13,048,468
10	Advances in Aid Of Const.	$ (7,214,952)	$ -	$ (7,214,952)
11	Contribution in Aid of Const.	$ (1,544,697)	$ -	$ (1,544,697)
12	Accumulated Amortization of CIAC	145,424	-	145,424
13	NET CIAC (L5 + L6)	$ (1,399,273)	$ -	$ (1,399,273)
14	Deferred Income Tax	$ (1,009,996)	$ -	$ (1,009,996)
15	Customer Deposits	$ -	$ (69,105)	$ (69,105)
16	Allowance for Working Capital	$ 89,405	$ (11,484)	$ 77,922
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 4,318,206	$ (885,143)	$ 3,433,064

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

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Schedule TJC-3
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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 42,011	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,011
2	Source of Supply Plant	2,098,977	-	-	(856,324)	-	-	-	1,242,653
3	Pumping Plant	1,400,953	-	-	-	-	-	-	1,400,953
4	Water Treatment Plant	845,417	-	-	-	-	-	-	845,417
5	Transmission & Distribution Plant	11,910,083	-	-	-	-	-	-	11,910,083
6	General Plant	762,698	-	-	-	-	-	-	762,698
7	Total Gross Plant in Service	$ 17,060,139	$ -	$ -	$ (856,324)	$ -	$ -	$ -	$ 16,203,815
8	Accumulated Depreciation	(3,207,118)	5,582	-	46,188	-	-	-	(3,155,348)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 13,853,022	$ 5,582	$ -	$ (810,136)	$ -	$ -	$ -	$ 13,048,468
10	Advances in Aid Of Const.	$ (7,214,952)	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,214,952)
11	Contribution in Aid of Const.	$ (1,544,697)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,544,697)
12	Accumulated Amortization of CIAC	145,424	-	-	-	-	-	-	145,424
13	NET CIAC (L5 + L6)	$ (1,399,273)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,399,273)
14	Deferred Income Tax	$ (1,009,996)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,009,996)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (69,105)	$ -	$ (69,105)
16	Allowance for Working Capital	89,405	$ -	$ -	$ -	$ -	$ -	$ (11,484)	$ 77,922
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 4,318,206	$ 5,582	$ -	$ (810,136)	$ -	$ (69,105)	$ (11,484)	$ 3,433,064

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

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Schedule TJC-7

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 1,458,989	$ -	$ 1,458,989	$ (71,427)	$ 1,387,562
2	Commercial	609,270	-	609,270	-	609,270
3	Industrial	8,657	-	8,657	-	8,657
4	Private Fire Service	1,673	-	1,673	-	1,673
5	Other Water Revenues	84,784	-	84,784	-	84,784
6	Total Water Revenues	$ 2,163,372	$ -	$ 2,163,372	$ (71,427)	$ 2,091,945
7	Miscellaneous	$ 51,580	$ -	$ 51,580	$ -	$ 51,580
8	Total Operating Revenues	$ 2,214,952	$ -	$ 2,214,952	$ (71,427)	$ 2,143,525
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	10,262	-	10,262	-	10,262
11	Pumping Expenses:	-				
12	Purchased Power	192,581	-	192,581	-	192,581
13	Purchased Gas	878	-	878	-	878
14	Other	64,710	-	64,710	-	64,710
15	Water Treatment Expenses	33,911	-	33,911	-	33,911
16	Transmission & Distribution Expenses	285,973	-	285,973	-	285,973
17	Customer Accounting Expenses	267,290	-	267,290	-	267,290
18	Sales Expense	890	-	890	-	890
19	Administrative & General Expenses	378,361	(12,236)	366,125	-	366,125
20	Total Operations & Maintenance Expense	$ 1,234,856	$ (12,236)	$ 1,222,620	$ -	$ 1,222,620
21	Depreciation & Amortization Expenses	$ 426,056	$ (34,032)	$ 392,024	$ -	$ 392,024
	Taxes					
22	Federal Income Taxes	$ 60,002	$ 30,150	$ 90,151	$ (22,593)	$ 67,559
23	State Income Taxes	13,218	6,642	19,860	(4,977)	14,883
24	Property Taxes	151,656	(8,458)	143,197	-	143,197
25	Other	52,532	(934)	51,598	-	51,598
26	Total Taxes	$ 277,407	$ 27,400	$ 304,807	$ (27,570)	$ 277,237
27	Total Operating Expenses	$ 1,938,319	$ (18,868)	$ 1,919,451	$ (27,570)	$ 1,891,881
28	Operating Income	$ 276,633	$ 18,868	$ 295,500	$ (43,857)	$ 251,644

References:
Column (A): Company Schedule C-1
Column (B): TJC-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): TJC-1
Column (E): Column (C) + Column (D)

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 1,458,989	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,458,989
2	Commercial	609,270	-	-	-	-	-	-	-	-	-	-	609,270
3	Industrial	8,657	-	-	-	-	-	-	-	-	-	-	8,657
4	Private Fire Service	1,673	-	-	-	-	-	-	-	-	-	-	1,673
5	Other Water Revenues	84,784	-	-	-	-	-	-	-	-	-	-	84,784
6	Total Water Revenues	$ 2,163,372	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,163,372
7	Miscellaneous	$ 51,580	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51,580
8	Total Operating Revenues	$ 2,214,952	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,214,952
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	10,262	-	-	-	-	-	-	-	-	-	-	10,262
11	Pumping Expenses:												
12	Purchased Power	192,581	-	-	-	-	-	-	-	-	-	-	192,581
13	Purchased Gas	878	-	-	-	-	-	-	-	-	-	-	878
14	Other	64,710	-	-	-	-	-	-	-	-	-	-	64,710
15	Water Treatment Expenses	33,911	-	-	-	-	-	-	-	-	-	-	33,911
16	Transmission & Distribution Expenses	285,973	-	-	-	-	-	-	-	-	-	-	285,973
17	Customer Accounting Expenses	267,290	-	-	-	-	-	-	-	-	-	-	267,290
18	Sales Expense	890	-	-	-	-	-	-	-	-	-	-	890
19	Administrative & General Expenses	378,361	(8,014)	-	(677)	-	-	(31)	-	-	(3,513)	-	366,125
20	Total Operations & Maintenance Expense	$ 1,234,856	$ (8,014)	$ -	$ (677)	$ -	$ -	$ (31)	$ -	$ -	$ (3,513)	$ -	$ 1,222,620
21	Depreciation & Amortization Expenses	$ 426,056	$ -	$ -	$ -	$ -	$ -	$ -	$ (34,032)	$ -	$ -	$ -	$ 392,024
	Taxes												
22	Federal Income Taxes	$ 60,002	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,150	$ 90,151
23	State Income Taxes	13,218	-	-	-	-	-	-	-	-	-	6,642	19,860
24	Property Taxes	151,656	-	-	-	-	-	-	-	(8,458)	-	-	143,197
25	Other	52,532	-	(934)	-	-	-	-	-	-	-	-	51,598
26	Total Taxes	$ 277,407	$ -	$ (934)	$ -	$ -	$ -	$ -	$ -	$ (8,458)	$ -	$ 36,791	$ 304,807
27	Total Operating Expenses	$ 1,938,319	$ (8,014)	$ (934)	$ (677)	$ -	$ -	$ (31)	$ (34,032)	$ (8,458)	$ (3,513)	$ 36,791	$ 1,919,451
28	Operating Income	$ 276,633	$ 8,014	$ 934	$ 677	$ -	$ -	$ 31	$ 34,032	$ 8,458	$ 3,513	$ (36,791)	$ 295,500

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule TJC-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule TJC-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule TJC-10
7 - Depreciation Expense	Testimony, WAR And Schedule TJC-11
8 - Property Tax Expense	Testimony, WAR And Schedule TJC-12
9 - Rate Case Expense	Testimony, WAR And Schedule TJC-13
10 Income Tax	Testimony, WAR And Schedule TJC-14

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

EXHIBIT
R-20
ADMITTED

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Oracle System - Surrebuttal
Schedule TJC-11
Page 1 of 1

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 7
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCOUNT NO.	ACCOUNT NAME	(A) RUCO PLANT VALUE	(B) COMPANY PROPOSED DEP. RATES	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization	$ 15	0.00%	$ -
2	302	Franchises	-	See Acct. 111	-
3	303	Other Intangibles	612	See Acct. 111	21
4	310.1	Water Rights	93,122	0.00%	-
5	310.3	Other Source of Supply Land	24,695	0.00%	-
6	310.4	Wells - Other	-	See Acct. 111	-
7	314	Wells	453,292	3.13%	14,188
8	320	Pumping Plant Land	2,742	0.00%	-
9	321	Pumping Plant Structures & Imprm'ts	72,186	2.86%	2,065
10	325	Electtric Pumping Equipment	876,909	5.88%	51,562
11	328	Gas Engine Equipment	-	4.00%	-
12	330	Water Treatment Plant Land	-	0.00%	-
13	331	Water Treatment Structures & Imprm'ts	35,054	2.50%	876
14	332	Water Treatment Equipment	69,067	2.86%	1,975
15	340	Transmission and Distribution Land	19,680	0.00%	-
16	342	Storage Tanks	306,126	2.00%	6,123
17	343	Transmission & Distribution Mains	3,051,729	1.79%	54,626
18	344	Fire Sprinkler Taps	-	2.00%	-
19	345	Services	584,527	2.38%	13,912
20	346	Meters	110,585	4.55%	5,032
21	348	Hydrants	121,938	1.82%	2,219
22	389	General Plant Land	-	0.00%	-
23	390	General Plant Structures	31,501	2.50%	788
24	390.1	Leasehold Improvements	30,004	See Acct. 108.2	-
25	391	Office Furniture & Equipment	104,701	6.67%	6,984
26	393	Warehouse Equipment	166	5.00%	8
27	394	Tools, Shop & Garage Equipment	27,072	4.00%	1,083
28	395	Laboratory Equipment	236	5.00%	12
29	396	Power Operated Equipment	33	6.67%	2
30	397	Communication Equipment	64,077	6.67%	4,274
31	398	Miscellaneous Equipment	4,862	3.33%	162
32		Rounding	(1)		
33		TEST YEAR GROSS PLANT AND DEPRECIATION EXPENSE	$ 6,064,930		$ 165,911
34					
35		AMORTIZATION OF CONTRIBUTIONS	(623,732)	2.00%	(12,475)
36		Rounding			-
37	**TOTAL DEPRECIATION EXPENSE**				$ 153,436
38					
39	Company As Filed				181,393
40	Difference				$ (27,957)
41					
42	RUCO Adjustment (See TJC-8, Column (B))				$ (27,957)

EXHIBIT
R-21
ADMITTED

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Casa Grande System - Surrebuttal
Schedule TJC-3
Page 1 of 1

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4 REGULATORY ASSET	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 1,975,834	$ (822,694)	$ -	$ -	$ -	$ -	$ -	$ 1,153,140
2	Source of Supply Plant	6,113,706	-	-	(896,925)	-	-	-	5,216,781
3	Pumping Plant	5,577,501	-	-	-	-	-	-	5,577,501
4	Water Treatment Plant	7,112,797	-	-	-	-	-	-	7,112,797
5	Transmission & Distribution Plant	80,496,004	-	-	-	-	-	-	80,496,004
6	General Plant	3,245,256	-	-	-	-	-	-	3,245,256
7	Total Gross Plant in Service	$ 104,521,097	$ (822,694)	$ -	$ (896,925)	$ -	$ -	$ -	$ 102,801,478
8	Accumulated Depreciation	(17,639,046)	(1,579)	-	676,446	-	-	-	(16,964,179)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 86,882,051	$ (824,273)	$ -	$ (220,479)	$ -	$ -	$ -	$ 85,837,300
10	Advances in Aid Of Const.	$ (29,671,663)	$ -	$ -	$ -	$ -	$ -	$ -	$ (29,671,663)
11	Contribution in Aid of Const.	$ (14,050,085)	$ -	$ -	$ -	$ -	$ -	$ -	$ (14,050,085)
12	Accumulated Amortization of CIAC	2,242,757	-	-	-	-	-	-	2,242,757
13	NET CIAC (L5 + L6)	$ (11,807,328)	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,807,328)
14	Deferred Income Tax	$ (5,088,308)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,088,308)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (252,738)	$ -	$ (252,738)
16	Allowance for Working Capital	383,959	$ -	$ -	$ -	$ -	$ -	$ (92,250)	$ 291,709
17	Net Regulatory Asset / (Liability)	$ 575,803	$ -	$ -	$ -	$ (14,289)	$ -	$ -	$ 561,514
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 41,274,515	$ (824,273)	$ -	$ (220,479)	$ (14,289)	$ (252,738)	$ (92,250)	$ 39,870,486

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimor
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - To Adjust Net Regulatory Asset
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

R-22

EASTERN GROUP

EXHIBIT
R-22
ADMITTED

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2 PER BKB 11.16 RETIREMENTS	(D) ADJMT NO. 3 PER BKB 11.16 PHFFU	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 43,332	$ -	$ -	$ -	$ -	$ -	$ -	$ 43,332
2	Source of Supply Plant	849,846	-	-	-	-	-	-	849,846
3	Pumping Plant	889,639	6,328	-	-	-	-	-	895,967
4	Water Treatment Plant	46,503	-	-	-	-	-	-	46,503
5	Transmission & Distribution Plant	7,664,743	-	-	-	-	-	-	7,664,743
6	General Plant	820,594	-	(704)	-	-	-	-	819,890
7	Total Gross Plant in Service	$ 10,314,658	$ 6,328	$ (704)	$ -	$ -	$ -	$ -	$ 10,320,281
8	Accumulated Depreciation	(4,218,432)	(10,913)	704	-	-	-	-	(4,228,641)
9	Net Utility Plant in Service (Sum L1 & L2)	$ 6,096,226	$ (4,585)	$ -	$ -	$ -	$ -	$ -	$ 6,091,641
10	Advances in Aid Of Const.	$ (258,981)	$ -	$ -	$ -	$ -	$ -	$ -	$ (258,981)
11	Contribution in Aid of Const.	$ (452,659)	$ -	$ -	$ -	$ -	$ -	$ -	$ (452,659)
12	Accumulated Amortization of CIAC	106,681	-	-	-	-	-	-	106,681
13	NET CIAC (L5 + L6)	$ (345,978)	$ -	$ -	$ -	$ -	$ -	$ -	$ (345,978)
14	Deferred Income Tax	$ (954,417)	$ -	$ -	$ -	$ -	$ -	$ -	$ (954,417)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (17,600)	$ -	$ (17,600)
16	Allowance for Working Capital	$ 124,134	$ -	$ -	$ -	$ -	$ -	$ (16,750)	$ 107,384
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 4,660,984	$ (4,585)	$ -	$ -	$ -	$ (17,600)	$ (16,750)	$ 4,622,049

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See TJC-4 Total, TJC-4 Direct, TJC-4 PHX OFF and TJC-4 MS Schedules and TJC Testimony)
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 7
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCOUNT NO.	ACCOUNT NAME	(A) RUCO PLANT VALUE	(B) COMPANY PROPOSED DEP. RATES	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization	$ 32	0.00%	$ -
2	302	Franchises	18,754	See Acct. 111	750
3	303	Other Intangibles	24,545	See Acct. 111	1,206
4	310.1	Water Rights	307,085	0.00%	-
5	310.3	Other Source of Supply Land	4,037	0.00%	-
6	310.4	Wells - Other	-	See Acct. 111	-
7	314	Wells	538,724	3.13%	16,862
8	320	Pumping Plant Land	7,054	0.00%	-
9	321	Pumping Plant Structures & Imprm'ts	33,537	2.86%	959
10	325	Electtric Pumping Equipment	683,491	5.88%	40,189
11	328	Gas Engine Equipment	171,885	4.00%	6,875
12	330	Water Treatment Plant Land	-	0.00%	-
13	331	Water Treatment Structures & Imprm'ts	1,452	2.50%	36
14	332	Water Treatment Equipment	45,051	2.86%	1,288
15	340	Transmission and Distribution Land	5,044	0.00%	-
16	342	Storage Tanks	369,280	2.00%	7,386
17	343	Transmission & Distribution Mains	5,385,816	1.79%	96,406
18	344	Fire Sprinkler Taps	51,566	2.00%	1,031
19	345	Services	1,346,780	2.38%	32,053
20	346	Meters	226,315	4.55%	10,297
21	348	Hydrants	279,943	1.82%	5,095
22	389	General Plant Land	2,384	0.00%	-
23	390	General Plant Structures	21,174	2.50%	529
24	390.1	Leasehold Improvements	73,769	See Acct. 108.2	175
25	391	Office Furniture & Equipment	324,678	6.67%	21,656
26	393	Warehouse Equipment	293	5.00%	15
27	394	Tools, Shop & Garage Equipment	75,839	4.00%	3,034
28	395	Laboratory Equipment	740	5.00%	37
29	396	Power Operated Equipment	16,632	6.67%	1,109
30	397	Communication Equipment	280,671	6.67%	18,721
31	398	Miscellaneous Equipment	23,709	3.33%	790
32		Rounding	(1)		
33		TEST YEAR GROSS PLANT AND DEPRECIATION EXPENSE	$ 10,320,281		$ 266,501
34					
35		AMORTIZATION OF CONTRIBUTIONS	(452,659)	2.00%	(9,053)
36		Rounding			-
37	**TOTAL DEPRECIATION EXPENSE**				$ 257,447
38					
39	Company As Filed				261,462
40	Difference				$ (4,015)
41					
42	RUCO Adjustment (See TJC-8, Column (B))				$ (4,015)
43					
44					
45	3-Factor Allocator By District:				
46	Superstition	24.94%	White Tank	2.37%	
47	Bisbee	4.98%	Ajo	0.81%	
48	Sierra Vista	2.58%	Coolidge	5.27%	
49	San Manuel	1.68%	Lakeside	6.20%	
50	Oracle	2.28%	Overgaard	3.99%	
51	Winkelman	0.22%	Sedona	8.45%	
52	Miami	4.98%	Pinewood	2.95%	
53	Casa Grande	26.55%	Rimrock	1.48%	
54	Stanfield	0.27%			

BEFORE THE ARIZONA CORPORATION C..

Arizona Corporation Commission
DOCKETED
NOV 27 2007
DOCKETED BY ne

EXHIBIT
R-23
ADMITTED

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831 DECISION NO. 70011 **OPINION AND ORDER**

DATES OF HEARING: April 16, 17, 18, 19, 20, 24, and 25, 2007.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

IN ATTENDANCE: Mike Gleason, Chairman
Kristin K. Mayes, Commissioner

APPEARANCES: Mr. Michael W. Patten and Mr. Timothy Sabo, ROSHKA, DEWULF & PATTEN, P.L.C. and Ms. Michelle Livengood, UNISOURCE ENERGY SERVICES, on behalf of Applicant;

Mr. Scott S. Wakefield, Chief Counsel, on behalf of the Residential Utility Consumer Office;

Ms. Cynthia Zwick, Executive Director, Arizona Community Action Association;

Mr. Marshall Magruder, in propria persona; and

Mr. Keith Layton and Ms. Maureen Scott, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

We agree with Staff that post-test-year plant should not be included in rate base for the same reasons stated above with respect to the Company's request for CWIP. Although the Commission has allowed post-test-year plant in several prior cases involving water companies, it appears that the issue was developed on the record in those proceedings in a manner that afforded assurance that a mismatch of revenues did not occur. For example, in Decision No. 66849 (March 19, 2004), we stated that "we do not believe that adoption of this method would result in a mismatch because the post-test-year plant additions are revenue neutral (*i.e.*, not funded by CIAC or AIAC)" (*Id.* at 5). In the instant case, however, the Company's request appears to be simply a fallback to its CWIP position, and there is no development of the record to support inclusion of the post-test-year plant. The entirety of UNS's argument consists of two questions in Mr. Grant's direct testimony, which essentially provided that: the Commission has approved post-test-year plant in some prior cases, UNS is experiencing a high customer growth rate, and therefore the Company is entitled to inclusion of post-test-year plant if the Commission denies CWIP (Ex. A-27 at 28-29). Even if we were inclined to recognize post-test-year plant in this case, there is not a sufficient basis upon which to evaluate the reasonableness of the request (*i.e.*, whether a mismatch would exist). We therefore deny the Company's proposal on this issue.

Deduction of Customer Advances

The final issue raised in UNS's trilogy of CWIP-related issues is its plea that the Commission should not reduce rate base to recognize funds received for customer advances, if the Commission rejects UNS's request for CWIP or, alternatively, for post-test-year plant. The Company concedes that such advances are typically deducted from rate base because they represent customer-supplied capital. However, UNS contends that it has received approximately $4 million in customer advances related to the $7 million in CWIP plant investment (Ex. A-28 at 27). Thus, according to UNS, the net impact on rates (if the requested $7 million of CWIP were to be included in rate base) is $3 million, based on the net of the $7 million offset by $4 million in advances.

UNS argues that it is inherently unfair to exclude the advances from rate base if the plant associated with those advances is not yet in service and not included in rate base. UNS claims that the purpose of deducting advances (*i.e.*, recognizing customer-supplied capital) is not furthered when

the plant is not in service. The Company also contends that the deduction of advances in this case would discourage utilities from seeking advances to offset infrastructure capital costs.

Both Staff and RUCO oppose the Company's recommendation. Staff witness Ralph Smith states that because advances represent non-investor-supplied capital, they should be reflected as a deduction to rate base. He stated that Staff is not aware of any instance in which CWIP was excluded for a major utility in Arizona and customer advances were not reflected as a deduction to rate base. Mr. Smith also cites to A.A.C. R14-2-103, Appendix B, Schedule B-1, which he claims requires companies to reflect advances as a deduction from rate base (Ex. S-27 at 15-16).

RUCO witness Marylee Diaz Cortez agreed with Staff's recommendation regarding advances. She testified that the Commission has historically excluded CWIP from rate base and recognized contributions (advances) as a deduction from rate base and that UNS is being afforded (under RUCO's and Staff's recommendations) the same rate base treatment as every other utility in Arizona (RUCO Ex. 6 at 8). Ms. Diaz Cortez claims that it is only the Company's proposal to include CWIP which creates a mismatch, because UNS failed to include the additional revenues the construction projects generate (*Id.* at 8-9).

We agree with Staff and RUCO that advances represent customer-supplied funds that are properly deducted from the Company's rate base. Indeed, the Commission's own rules contemplate that such a deduction is required, as Staff witness Smith testified. Had UNS not requested the inclusion of CWIP in rate base, a ratemaking treatment that is only afforded under extraordinary circumstances (and apparently has not occurred for more than 20 years), there would presumably not have been an issue raised by the Company with respect to an alleged "mismatch" between exclusion of CWIP and deducting advances from rate base. The Company's attempt to frame this issue as one in which it is being treated in a discriminatory manner is unpersuasive.

As we have stated in prior cases, regulated utility companies control the timing of their rate case filings and should not be heard to complain when their chosen test periods do not coincide with the completion of plant that may be considered used and useful and therefore properly included in rate base. We believe our conclusions regarding UNS's CWIP-related proposals are entirely

consistent with the treatment that has been afforded to other utility companies regulated by the Commission and provide a result that is fair to both the Company and its customers.

Geographic Information System

UNS seeks to include in rate base $897,068 for expenses incurred during 2003 and 2004 to install a Geographic Information System ("GIS"). The GIS is a global positioning system that allows UNS to locate existing service lines. UNS witness Gary Smith testified that the Company installed the GIS in response to a Commission Pipeline Safety audit that recommended a complete mapping of the UNS system. He described several benefits of the GIS, including improved response times, better informed decisions regarding adding system infrastructure, and increased accuracy for field staff (Ex. A-15 at 6-7).

According to Staff witness Ralph Smith, the GIS costs should not be included in rate base because they were non-recurring expenses that were largely incurred outside of the test year. He explained that, according to internal Company memos, UNS initially decided to treat the GIS as a capitalized investment, but later determined that capitalization of the costs was inappropriate under Generally Accepted Accounting Principles ("GAAP"). Mr. Smith stated that, under GAAP, the GIS costs were required to be expensed during the period in which they were incurred and, since they were incurred prior to the test year, are not properly includable in rates (Ex. S-27 at 16-18).

RUCO also opposes inclusion of the GIS expenses in rates. RUCO witness Marylee Diaz Cortez stated that because UNS failed to obtain from the Commission an accounting order to treat the GIS expenses as a regulatory asset, which would be eligible for future rate recovery consideration, the Company is not entitled to recover those costs in this rate proceeding (RUCO Ex. 5 at 11-12; RUCO Ex. 6 at 9-10). RUCO argues that regardless of the Company's increased productivity claims, its failure to properly account for the GIS costs precludes recovery in UNS's rate base.

We agree with Staff and RUCO that the GIS costs are not properly recoverable as a regulatory asset in this proceeding. As described by Staff witness Ralph Smith, the GIS costs were required by GAAP to be expensed, and the vast majority of those costs were incurred prior to the test year and are non-recurring in nature (Ex. S-25 at 12-17). Further, the Company's failure to seek an accounting order from the Commission when the costs were incurred renders them unrecoverable as a regulatory

TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS; SECURITIES REGULATION

CHAPTER 2. CORPORATION COMMISSION FIXED UTILITIES

Authority: Article XV, § 3, Constitution of Arizona and A.R.S. § 40-202 et seq.

Editor's Note: The Office of the Secretary of State publishes all Code Chapters on white paper (Supp. 02-1).

The Corporation Commission has determined that rules in this Chapter are exempt from the Attorney General certification provisions of the Arizona Administrative Procedure Act (A.R.S. § 41-1041) by a court order (State ex. rel. Corbin v. Arizona Corporation Commission, 174 Ariz. 216 848 P.2d 301 (App. 1992)). This exemption means that the rule was not certified by the Attorney General. Because this Chapter was filed under a rulemaking exemption, as determined by the Corporation Commission, other than a statutory exemption, the Chapter is printed on green paper.

Chapter 2, consisting of Sections R14-2-104, R14-2-105, R14-2-201 through R14-2-213, R14-2-301 through R14-2-313, R14-2-401 through R14-2-411, R14-2-501 through R14-2-510, and R14-2-601 through R14-2-610, adopted effective March 2, 1982.

ARTICLE 1. GENERAL PROVISIONS

Former Sections R14-2-103, R14-2-127, and R14-2-128, renumbered as Sections R14-2-101 through R14-2-103 respectively and former Section R14-2-135 renumbered as Section R14-2-314 effective March 2, 1982.

Former Sections R14-2-101, R14-2-102, R14-2-104, R14-2-106 through R14-2-126, R14-2-129, R14-2-130, R14-2-132 through R14-2-134 repealed effective March 2, 1982.

Section
R14-2-101. Accident reports
R14-2-102. Treatment of depreciation
R14-2-103. Defining Filing Requirements in Support of a Request by a Public Service Corporation Doing Business in Arizona for a Determination of the Value of Property of the Corporation and of the Rate of Return Thereon, or in Support of Proposed Increased Rates or Charges
R14-2-104. Inspection of annual reports
R14-2-105. Notice of rate hearings
R14-2-106. Commission Color Code to Identify Location of Underground Facilities

ARTICLE 2. ELECTRIC UTILITIES

Section
R14-2-201. Definitions
R14-2-202. Certificate of Convenience and Necessity for Electric Utilities
R14-2-203. Establishment of Service
R14-2-204. Minimum Customer Information Requirements
R14-2-205. Master Metering
R14-2-206. Service Lines and Establishments
R14-2-207. Line Extensions
R14-2-208. Provision of Service
R14-2-209. Meter Reading
R14-2-210. Billing and Collection
R14-2-211. Termination of Service
R14-2-212. Administrative and Hearing Requirements
R14-2-213. Conservation

ARTICLE 3. GAS UTILITIES

Section
R14-2-301. Definitions
R14-2-302. Certificate of Convenience and Necessity for gas utilities; additions/extensions; abandonments
R14-2-303. Establishment of service
R14-2-304. Minimum customer information requirements
R14-2-305. Master metering
R14-2-306. Service lines and establishments
R14-2-307. Main extensions
R14-2-308. Provision of service
R14-2-309. Meter reading
R14-2-310. Billing and collection
R14-2-311. Termination of service
R14-2-312. Administrative and Hearing Requirements
R14-2-313. Conservation
R14-2-314. Intermittent gas ignition

ARTICLE 4. WATER UTILITIES

Section
R14-2-401. Definitions
R14-2-402. Certificate of Convenience and Necessity for water utilities; abandonments
R14-2-403. Establishment of service
R14-2-404. Minimum customer information requirements
R14-2-405. Service connections and establishments
R14-2-406. Main extension agreements
R14-2-407. Provision of service
R14-2-408. Meter reading
R14-2-409. Billing and collection
R14-2-410. Termination of service
R14-2-411. Administration and Hearing Requirements

ARTICLE 5. TELEPHONE UTILITIES

Section
R14-2-501. Definitions
R14-2-502. Certificate of Convenience and Necessity for telephone utilities; additions/extensions; abandonments
R14-2-503. Establishment of service
R14-2-504. Minimum customer information requirements
R14-2-505. Service connections and establishments
R14-2-506. Construction Agreement
R14-2-507. Provision of Service
R14-2-508. Billing and collection
R14-2-509. Termination of service
R14-2-510. Administrative and Hearing Requirements

ARTICLE 6. SEWER UTILITIES

Section
R14-2-601. Definitions
R14-2-602. Certificate of Convenience and Necessity for sewer utilities; additions/extensions; abandonments
R14-2-603. Establishment of service
R14-2-604. Minimum customer information requirements
R14-2-605. Service connections
R14-2-606. Collection main extension agreements
R14-2-607. Provision of service
R14-2-608. Billing and collection
R14-2-609. Termination of service
R14-2-610. Administrative and Hearing Requirements

3. Data and analyses supporting the change shall be submitted, including engineering data and assessment of the impact and appropriateness of the change for ratemaking purposes.
4. Changed depreciation rates shall not become effective until the Commission authorizes such changes.

D. Upon the motion of any party or upon its own motion, the Commission may determine that good cause exists for granting a waiver from one or more of the requirements of this Section.

Historical Note

Former Section R14-2-102 repealed, former Section R14-2-127 renumbered as Section R14-2-102 without change effective March 2, 1982 (Supp. 82-2). Forward to the rule corrected as filed April 13, 1973 (Supp. 89-1). Section R14-2-102 repealed, new Section adopted effective April 9, 1992 (Supp. 92-2).

R14-2-103. Defining Filing Requirements in Support of a Request by a Public Service Corporation Doing Business in Arizona for a Determination of the Value of Property of the Corporation and of the Rate of Return Thereon, or in Support of Proposed Increased Rates or Charges

A. Purpose and definitions

1. Purpose: The purpose of this General Order is to define the specific financial and statistical information required to be filed with a request by a public service corporation doing business in Arizona for a determination of the value of the property of the corporation and of the rate of return to be earned thereon, with regard to proposed increased rates or charges. This General Order does not apply to the implementation of previously approved adjustment or escalation clauses.
2. Applicability of rules: These rules shall apply to all electric, gas, telephone, telegraph, water and private fire protection public service corporations under the jurisdiction of the Commission. These rules are applicable both to all filings made after the effective date of this General Order and to any rate proceeding pending on the effective date of this General Order in which the Commission has issued no final decision. These rules are not intended to prohibit utilities from filing additional schedules, exhibits and other documents in which the Commission has issued no final decision. These rules are not intended to prohibit utilities from filing additional schedules, exhibits and other documents which may be material to the rate proceeding, nor are they intended to prohibit the Commission from considering such schedules, exhibits or other documents in making its determination. In pending proceedings, to the extent that the information required by this General Order is not included in the public service corporation's exhibits or is not otherwise in the record, such information shall be supplied as soon as possible unless a waiver is requested and granted pursuant to subsection (B)(5).
3. Definitions: Terminology used in this General Order is defined as follows:
   a. "Accounting method" -- the accounting method prescribed or recognized by the Commission.
   b. "Commission" -- The Arizona Corporation Commission.
   c. "Cost of service" -- The total cost of providing service to a defined segment of customers, as determined by the application of logical and generally accepted cost analysis and allocation techniques.
   d. "Department" -- A responsibility center within a combination utility where revenues and costs are accumulated by commodity or service rendered.
   e. "Depreciated original cost" -- The cost of property to the person first devoting it to public service, less the depreciation reserve, which shall include accrued depreciation and amortization calculated in accordance with General Order R14-2-102. Depreciated original cost shall not include any goodwill or going concern value, nor shall it include certificate value in excess of payment made or costs incurred in the initial acquisition thereof.
   f. "Exhibit" -- One or more schedules which support a rate filing or testimony in a rate proceeding.
   g. "Filing" -- An application and required schedules, exhibits or other documents filed by a public service corporation to initiate any proceeding enumerated in subsection (A)(1). For all Class A and B utilities and for Class C electric and gas utilities, the filing shall include direct testimony in support of the application. For Class C water, sewer, and telephone utilities and for all Class D and E utilities, the filing shall include a written description of the components of the application. Nothing in this Section shall be construed to prohibit a public service corporation, prior to making a filing, from giving the Commission informal pre-filing notice of its intent to make a filing. Such pre-filing notice would permit the Commission, on a tentative basis, to assign a hearing date and would permit agreement on an appropriate test year.
   h. "Original cost rate base" -- An amount consisting of the depreciated original cost, prudently invested, of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used or useful, plus a proper allowance for working capital and including all applicable pro forma adjustments.
   i. "Pro forma adjustments" -- Adjustments to actual test year results and balances to obtain a normal or more realistic relationship between revenues, expenses and rate base.
   j. "Projected year" -- The year immediately following the test year.
   k. "Projections" -- Estimate of future results of operations based upon known facts or logical assumptions concerning future events.
   l. "Prudently invested" -- Investments which under ordinary circumstances would be deemed reasonable and not dishonest or obviously wasteful. All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made.
   m. "Rate schedule" -- A schedule of rates and conditions for a specific classification of customer or for other specific services.
   n. "Reconstructed Cost New (RCND) Rate Base" -- An amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable

pro forma adjustments. Contributions and advances in aid of construction, if recorded in the accounts of the public service corporation, shall be increased to a reconstruction new basis.

o. "Staff" -- The staff of the Commission or its designated representatives.

p. "Test year" -- The one-year historical period used in determining rate base, operating income and rate of return. The end of the test year shall be the most recent practical date available prior to the filing.

q. "Utilities" -- For purposes of the Section, utilities are electric, gas, telephone, water, sewer or any other that may be supplying service and/or commodities which in the future may be adjudged a public service corporation and under the jurisdiction of this Commission, are classified as follows:

	Annual Operating Revenue				
	Class A	B	C	D	E
Electric & Gas	Exceeding $5,000,000	$1,000,000 to $5,000,000	$250,000 to $999,000	$50,000 to $249,999	Less than $50,000
Water & Sewer	Exceeding $5,000,000	$1,000,000 to $5,000,000	$250,000 to $999,000	$50,000 to $249,999	Less than $50,000
Telephone	Exceeding $1,000,000	$250,000 to $1,000,000	$100,000 to $249,000	$25,000 to $99,999	Less than $25,000

Annual operating revenues are those gross utility operating revenues derived from jurisdictional operations, including the requested rate relief. A combination utility is a utility which provides more than one of the commodities or services enumerated in this subsection. For combination utilities, the annual operating revenue, including the requested rate relief, for the specific subsidiary, department, or operating division requesting the rate change shall be used for classification purposes.

r. "Working capital" -- A proper allowance for cash, materials and supplies and prepayments.

B. Filing requirements:

1. Information required from Class A, B, C and D utilities except for electric distribution cooperatives whose filing requirements are detailed in subsection (B)(3): The information required to be prepared and submitted by Class A, B, C and D Utilities in conjunction with a filing is presented below. Corresponding schedule formats are contained in the Appendix of this General Order and denoted. These formats are not applicable to Class E utilities. The Appendix schedule formats A-1 through A-5 are a part of this General Order, and the Applicant's schedules should conform to these formats. All other Appendix schedule formats and descriptions are illustrative and the applicant's specific formats may vary from that suggested in the Appendix. The substantive information requested, both on the Appendix schedule and in the body of this General Order, however, must be contained on the applicant's schedules together with the titles and schedule numbers provided in the Appendix. Specific information items requested on the Appendix schedules may be omitted without formal waiver, from the filing where it is evident that said items are not applicable to the applicant's business. The instructions and notes contained on the Appendix schedules shall be followed where applicable. Reconstruction Cost New Depreciated information not filed by the applicant shall be deemed waived.

Information	Filing Required by	Appendix Schedule Reference(s)
A. Summary Information:		
1. A summary of the increase in revenue requirements and the spread of the revenue increase by customer classification.	All classes	A-1
2. A summary of the results of operations for the test year and for the test year and the 2 fiscal years ended prior to the end of the test year, compared with the projected year.	All classes	A-2
3 A summary of the capital structure for the test year and the 2 fiscal years ended prior to the end of the test year, compared with the projected year.	Classes A & B	A-3
4. Construction expenditures and gross utility plant in service for the test year and the 2 fiscal years ended prior to the end of the test year, compared with the projected year.	All classes	A-4
5. A summary of changes in financial position for the test year and the 2 fiscal years ended prior to the end of the test year, compared with the projected year.	Classes A & B	A-5
B. Rate Base Information:		
1. A schedule showing the elements of original cost and RCND rate bases.	All classes	B-1
2. A schedule listing pro forma adjustments to gross plant in service and accumulated depreciation for the original cost rate base.	All classes	B-2
3. A schedule showing pro forma adjustments to gross plant in service and accumulated depreciation for the RCND rate base.	All classes	B-3
4. A schedule demonstrating the determination of reproduction cost new less depreciation at the end of the test period.	All classes	B-4
5. A schedule showing the computation of working capital allowance.	All classes	B-5
C. Test Year Income Statements:		
1. A test year income statement, with pro form adjustments.	All classes	C-1
2. A schedule showing the detail of all pro forma adjustments.	All classes	C-2
3. A schedule showing the incremental taxes and other expenses on gross revenues and the computation of an incremental gross revenue conversion factor.	All classes	C-3

	Information	Filing Required by	Appendix Schedule Reference(s)
D.	Cost of Capital Information:		
1.	A schedule summarizing the elements in the capital structure at the end of the test year and the projected year, their related costs and the computation of the total cost of capital.	All classes	D-1
2.	A schedule showing the detail of long-term and short-term debt at the end of the test year and the projected year and their total cost.	Classes A & B	D-2
3.	A schedule showing the detail of preferred stock at the end of the test year and the projected year, and their total cost.	Classes A & B	D-3
4.	A schedule summarizing conclusions of the required return on the common equity as of the end of the test year and the projected year.	Classes A & B	D-4
E.	Financial Statements and Statistical Data:		
1.	Comparative balance sheets for the end of the test year and the 2 fiscal years ended prior to the end of the test year.	All classes	E-1
2.	Comparative income statements for the test year and the 2 fiscal years ended prior to the end of the test year.	All classes	E-2
3.	Comparative statements of changes in financial position for the test year and the 2 fiscal years ended prior to the end of the test year.	Classes A & B	E-3
4.	Statements of changes in stockholder's equity for the test year and the 2 fiscal years ended prior to the end of the test year.	Classes A & B	E-4
5.	A comparative schedule showing by detail account number, utility plant balances at the end of the test year and the end of prior fiscal year.	All classes	E-5
6.	Comparative departmental statements of operating income for the test year and the 2 fiscal years ended prior to the end of the test year.	All classes of combination utilities	E-6
7.	Comparative operating statistics on customers, consumption, revenues, and expenses for the test year and the 2 fiscal years ended prior to the end of the test year.	All classes	E-7
8.	A comparative schedule of all significant taxes charged to operations for the test year and the 2 fiscal years ended prior to the end of the test year.	All classes except Class D	E-8
9.	Audited financial statements, if available, for the test year and the 2 fiscal years ended prior to the end of the test year. If the financial statements have not been audited, notes to the financial statements should be provided to indicate accounting method, depreciation lives and methods, income tax treatment and other important disclosures.	All classes	E-9
F.	Projections and Forecasts:		
1.	A projected income statement for the projected year compared with actual test year results, at present rates and proposed rates.	All classes	F-1
2.	Projected changes in financial position for the projected year compared with the test year, at present rates and proposed rates.	Classes A & B	F-1
3.	Projected annual construction requirements, by property classification, for 1 to 3 years subsequent to the test year, compared with the test year.	Classes A & B 3 years Classes C & D 1 year	F-3
4.	Important assumptions used in preparing forecasts and projections.	All classes	F-4
G.	Cost of Service Information		
	A utility shall submit cost of service analyses and studies if all of the following conditions prevail:		
1.	The utility is in a segment of the utility industry that recognizes cost of service studies as important tools for rate design.		
2.	Costs incurred by the utility are likely to vary significantly from 1 defined segment of customers to another.		
	A historical accounting period other than the test year may be used for cost of service purposes provided that customer mix in the historical period used is representative of the test year. When a cost of service analysis is required, the following information shall be submitted:		
1.	Schedule showing rates of return by customer classification at present and proposed rates.	Classes A, B and C if applicable	G-1 G-2
2.	Schedules showing the approach used in allocating or assigning plant and expenses to classes of service and defined functions.	Classes A, B and C if applicable	G-3 G-4 G-5 G-6
3.	Schedules showing the development of all allocation factors used in the all allocation factors used in the cost of service study.	Classes A, B and C if applicable	G-7
H.	Effect of Proposed Rate Schedules:		
1.	A comparison of revenues by customer classification or other classification of revenues for the test year, at present and proposed rates.	All classes	H-1
2.	A comparison of revenues by class of service and by rate schedule for the test year, at present and proposed rates.	Classes A & B	H-2
3.	A comparison of present and proposed rate schedules or representative rate schedules.	Class A representative schedules; Classes B, C and D - all schedules	H-3
4.	Typical bill analysis	All classes	H-4
5.	Bill count	All classes	H-5

ARIZONA CORPORATION COMMISSION
REGULATION R14-2-103

APPENDIX B
RATE BASE SCHEDULES

ARIZONA CORPORATION COMMISSION REGULATION R14-2-103 APPENDIX ILLUSTRATIVE SCHEDULE FORMAT	Schedule: B-1 Title: Summary of Original Cost and RCND Base Elements
Explanation: Schedule showing elements of adjusted original cost and RCND rate bases.	Required For: All Utilities [x] Special Reqmt. [ ] Class A [ ] Class B [ ] Class C [ ] Class D [ ]

	Original Cost Rate Base*		RCND Rate Base*
1. Gross Utility Plant in Service$	$		
2. Less: Accumulated Depreciation			
3. Net Utility Plant in Service	$ (a)	$	(b)
Less:			
4. Customers' Advances for Construction	(c)		(c)
5. Contributions in Aid of Construction	(c)		(c)
Add:			
6. Allowance for Working Capital	(d)		(d)
7. Total Rate Base	$ (e)		$ (e)

* Including pro forma adjustments

Note: For combination utilities, above information should be presented in total and by department.

Supporting Schedules:			Recap Schedules:
(a) B-2	(d) B-5	(e)	A-1
(b) B-3			
(c) E-1			

EXHIBIT
tabbies
R-25
ADMITTED

PUBLIC UTILITY WORKING CAPITAL

Carl W. Dabelstein, CPA

Generally, equal installment payments are assumed to be made. If a company does not make equal installments, or pays sooner than required, due to specific facts and circumstances, such factors may be considered in the calculations.

One question that is frequently asked is whether the effect on cash working capital of income taxes associated with requested rate increases should be reflected in the lead/lag study underlying a rate case filing. Additional federal and state income taxes due to a change in revenues certainly have an effect on working capital; however, it seems to be more appropriate that the computed cash working capital component of rate base reflect only the income taxes applicable to adjusted test-year operating results. The incremental effect of additional revenues can be included as a component in the revenue conversion factor, that ratio used to determine the revenue equivalent of a change in net operating income. That way the allowance for cash working capital does not have to be recomputed every time an adjustment to filed data is made or differences reduced through negotiation.

Interest and Dividends

In those jurisdictions where some or all of the components of the return are included in lead/lag studies, the payment lag factors are fairly simple to determine. Interest is usually paid at the end of each of two semi-annual periods. This equates to an average lag of approximately 91 days.

Dividends on preferred stock are typically paid four times a year, with cash disbursed either at the end of the quarterly period, or sometime thereafter (i.e., end of following month), in

accordance with the underlying preferred stock agreement. The payment lead is computed as follows:

$$\frac{365 \text{ days}}{4 \text{ payments} \times 2} + \text{Average number of days from end of quarter to payment date}$$

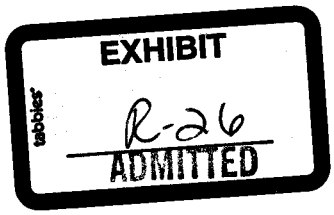
In those rare instances where the common equity return is permitted to be reflected in lead/lag studies, it is shown in its entirety with a zero payment lag, or may be divided into two pieces, that portion which is paid out in cash dividends (based on current dividend policies), and that which is reinvested. The portion paid out currently would indicate a lag computed in the same manner as that described above for preferred stock dividends. The reinvested portion would reflect a zero payment lag.

Other Costs of Service

After the respective payment leads and lags for each of the cost of service elements segregated for individual analysis have been determined, the remaining costs of service are grouped for the purpose of developing a single lag factor, based on a review of cash disbursement vouchers. In fact, this is often called the "voucher lag."

The standard procedure is to select a representative sample of vouchers and determine the overall average payment lag. For this purpose, the measurement period extends from the date (or midpoint of the period) during which respective goods and services were received, to the date of payment (See Exhibit VI-13). Items of an unusual or nonrecurring nature should be excluded from the analysis, as well as any items not relating to the provision of utility service.

TJC - Exhibit To Testimony
Adjustment Nos. 6 and 7



RUCO'S CASH WORKING CAPITAL ADJUSTMENT

Superstition	$	(93,495)
Bisbee		(16,750)
Sierra Vista		(10,107)
San Manuel		(24,710)
Oracle		(10,051)
Winkelman		(1,171)
Miami		(28,370)
Casa Grande		(92,250)
Stanfield		(3,738)
White Tank		(71,942)
Ajo		(21,159)
Coolidge		(11,484)
Lakeside		(26,088)
Overgaard		(13,463)
Pinewood		(6,536)
Rimrock		(9,921)
Sedona		(49,005)
Total	$	(490,240)

ARIZONA WATER COMPANY

DOCKET NO. W-014457A-08-0440

DIRECT TESTIMONY
ON REVENUE REQUIREMENT

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 12, 2009

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INTRODUCTION

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

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. I have been involved with utilities regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Arizona Water Company's ("AWC" or the "Company") application for a permanent rate increase ("Application") for the Company's statewide operations in Arizona. AWC filed the Application with the Arizona Corporation Commission ("ACC" or "Commission") on August 22, 2008. The Company has chosen the operating period ended December 31, 2007, for the test year ("Test Year") in this proceeding.

Q. Please describe AWC's organization.

A. AWC is comprised of eighteen separate operating systems that are organized into three different geographical groups: the Eastern Group which includes the Company's Superstition[1], Bisbee, Sierra Vista, San Manuel, Oracle, Saddlebrook, Winkelman, and Miami Systems; the Western Group which is made up of AWC's Casa Grande, Stanfield, White Tank, Ajo and Coolidge Systems; and, the Northern Group, which is comprised of the Company's Lakeside, Overgaard, Sedona, Pinewood and Rimrock Systems. AWC is seeking rate relief on a partial rate consolidation basis for seventeen of the aforementioned systems. According to AWC's Application, the Eastern Group's Saddlebrook System does not currently provide service to any permanent residential

[1] The Superstion System is comprised of two non-interconnected water systems serving Apache Junction and Superior. The two systems were consolidated for ratemaking purposes in a prior rate case proceeding that involved the Company's Eastern Group (Decision No. 66849, Dated March 19, 2004).

customers and is not part of this rate application. Per a condition of Decision No. 62754, the Company is required to file a rate application within thirty-six months of the date the Saddlebrook System provides service to a permanent residential customer.

Q. Please explain your role in RUCO's analysis of AWC's Application.

A. I reviewed AWC's Application to determine if the rates and charges being requested by the Company are appropriate. My testimony will cover the levels of operating revenues and expenses that are being proposed by the Company for the seventeen systems included in the Company's filing. I will also address a number of surcharges and pass-through mechanisms for which AWC is seeking Commission approval.

Q. Will you also address the rate base issues in this case?

A. No. The rate base issues associated with the case will be addressed by RUCO witness Timothy J. Coley.

Q. Are you presenting ratemaking schedules for each of the seventeen systems that AWC has included in its application?

A. No. I will be presenting ratemaking schedules for the five systems that are included in the Company's Northern Group. Mr. Coley will sponsor ratemaking schedules for the remaining twelve systems that make up AWC's Eastern and Western Groups. The rate base adjustments that Mr.

Coley discusses in his direct testimony appear in Schedules WAR-2 through WAR-6 for the Northern Group systems that I sponsor and Schedules TJC-2 through TJC-6 for the Eastern and Western Group systems that Mr. Coley sponsors. The operating revenue and expense adjustments that I will discuss appear on Schedules WAR-7 through WAR-15 for the Northern Group systems that I am sponsoring in my direct testimony and Schedules TJC-7 through TJC-15 for the Eastern and Western Group systems that Mr. Coley is sponsoring in his direct testimony.

Q. Who will provide direct testimony on RUCO's recommended rate design?

A. RUCO's direct testimony on rate design will be provided by RUCO witness Rodney L. Moore. Under the current Procedural Order, testimony on rate design and cost of service is scheduled to be filed on Friday, June 26, 2009.

Q. Will Mr. Coley, Mr. Moore or you offer direct testimony on rate consolidation at this time?

A. No. RUCO reserves the right to file testimony on rate consolidation during the surrebuttal phase of the proceeding upon review of rate design and engineering reports to be filed June 26, 2009. RUCO Director Jodi Jerich will file testimony on RUCO's position regarding the issue of rate consolidation at that time. Mr. Coley, Mr. Moore and I will present updated

ratemaking and rate design schedules that reflect RUCO's position regarding rate consolidation at that time also. The ratemaking schedules sponsored by Mr. Coley and I during the direct testimony phase of the proceeding will present the effects of RUCO's recommended levels of rate base, operating revenue and operating expenses on a stand-alone basis for each of the seventeen systems included in AWC's filing. Mr. Moore's direct testimony on rate design will also reflect rates on a stand-alone basis also.

Q. Is RUCO providing testimony on the cost of capital issues associated with the case?

A. Yes. I have also filed, under separate cover, testimony on the cost of capital issues associated with the case.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your direct testimony is organized.

A. My direct testimony is organized into four sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my analysis of AWC's Application and will explain the various operating revenue and expense adjustments that I am recommending. Fourth, and finally, I will discuss my recommendations regarding AWC's request for a number of surcharges and pass-through mechanisms.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of AWC, I am making the following recommendations related to operating revenues and expenses:

RUCO Operating Adjustment #1 – Labor Expense – This adjustment normalizes overtime hours that were incurred during the Test Year and reduces the Company's labor expense to reflect a more normal level of dollars paid for employee overtime. The adjustment is the first of four adjustments that affect all seventeen of AWC's operating systems.

RUCO Operating Adjustment #2 – Payroll Tax Expense – This is the second of four adjustments related to the level of employee overtime incurred during the Test Year. The adjustment normalizes payroll tax expense associated with the excess overtime labor expense removed in RUCO Operating Expense Adjustment #1. The adjustment affects all seventeen of AWC's operating systems.

RUCO Operating Adjustment #3 – Payroll 401(k) Expense – This is the third of four adjustments related to the level of employee overtime incurred during the Test Year. The adjustment normalizes Company 401(k) retirement program contributions incurred during the Test Year. The adjustment removes 401(k) expense dollars associated with the excess

overtime labor expense removed in RUCO Operating Expense Adjustment #1. The adjustment affects all seventeen of AWC's operating systems.

RUCO Operating Adjustment #4 – Reverse Adjustment for Conservation – This adjustment reverses a Company adjustment designed to recover revenues that may be lost as a result of implementing a conservation-oriented, three-tiered inverted block rate design in this proceeding for the AWC's Northern Group. The adjustment affects the five operating systems that make up the Company's Northern Group.

RUCO Operating Adjustment #5 – Purchased Power Revenues – This adjustment reverses an adjustment made by the Company to remove revenues pursuant to AWC's purchased power adjustment mechanism ("PPAM") that is currently in effect for all five of the Company's Northern Group systems. The adjustment is consistent with RUCO's recommendations to eliminate the Northern Group PPAM and to reject AWC's proposal to establish PPAM's for the Company's Eastern and Western Group systems.

RUCO Operating Adjustment #6 – Insurance Expense – This minor adjustment is the last of four adjustments related to overtime pay that was recorded during the Test Year. The adjustment removes a portion of long-term disability insurance expense that is associated with the excess

overtime labor expense removed in RUCO Operating Expense Adjustment #1. The adjustment affects all seventeen of AWC's operating systems.

RUCO Operating Adjustment #7 – Depreciation Expense – This adjustment calculates depreciation and amortization expense based on RUCO's recommended plant levels. The adjustment affects all seventeen of AWC's operating systems.

RUCO Operating Adjustment #8 – Property Tax Expense – This adjustment calculates property tax expense based on a modified Arizona Department of Revenue ("ADOR") formula that has been adopted by the Commission in a number of prior rate cases. The adjustment affects all seventeen of AWC's operating systems.

RUCO Operating Adjustment #9 – Rate Case Expense – This adjustment reflects RUCO's best estimate of rate case expense, to be amortized over three years, for this proceeding based on updated information provided by the Company. The adjustment affects all seventeen of AWC's operating systems.

RUCO Operating Adjustment #10 – Income Tax Expense – This adjustment calculates the appropriate level of income tax expense given

RUCO's recommended operating income. The adjustment affects all seventeen of AWC's operating systems.

Adjustor Mechanisms – RUCO recommends that the Commission reject the Company's request for adjustor mechanisms for purchased power, water, fuel and an adjustor for earnings attrition. RUCO recommends that the Commission eliminate the Northern Group PPAM and reject AWC's proposal to reestablish PPAM's for the Company's Eastern and Western Group systems. RUCO also recommends that the Commission reject AWC's request to reestablish a purchased water adjustor mechanism ("PWAM") for the Company's Eastern and Western Groups. RUCO further recommends that the Commission deny AWC's request for a purchased fuel adjustor mechanism ("PFAM") for all of the Company's operating systems. Finally RUCO recommends that AWC's request for an attrition adjustor mechanism ("AAM") as an alternative to the aforementioned adjustor mechanisms also be denied.

REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of Arizona Water Company and your recommended revenue requirement.

A. Based on the results of RUCO's analysis of AWC's rate application, RUCO is recommending that revenue for each of the Company's

seventeen operating systems should be increased by no more than the following amounts on a stand-alone (i.e. non-consolidated) basis:

Eastern Group Systems	RUCO's Recommended Increase/(Decrease) In Operating Revenue	Percentage Increase/ (Decrease)
Superstition	$2,160,482	18.09%
Bisbee	$271,233	15.74%
Sierra Vista	($163,188)	(11.16%)
San Manuel	$302,504	37.24%
Oracle	($70,482)	(6.26%)
Winkleman	$17,035	17.26%
Miami	$665,054	35.94%
Total Eastern Group	**$3,182,638**	

Western Group Systems	RUCO's Recommended Increase/(Decrease) In Operating Revenue	Percentage Increase/ (Decrease)
Casa Grande	$3,699,044	33.83%
Stanfield	$136,067	103.00%
White Tank	$317,918	25.54%
Ajo	$39,808	8.45%
Coolidge	($67,182)	(3.03%)
Total Western Group	**$4,125,655**	

Western Group Systems	RUCO's Recommended Increase/(Decrease) In Operating Revenue	Percentage Increase/ (Decrease)
Lakeside	($69,552)	(2.72%)
Overgaard	($277,183)	(16.44%)
Sedona	$975,545	27.73%
Pinewood	($7,224)	(0.69%)
Rimrock	$366,377	72.19%
Total Northern Group	**$987,963**	
Total Company	**$8,296,256**	

RUCO's recommended increase in operating revenue is $7,145,034 lower than the $15,441,290 level of increase requested by AWC. The recommendations listed above are summarized on Schedule WAR-1 for the Northern Group systems in my direct testimony and Schedule TJC-1 for the Eastern and Western Group systems that are included in the direct testimony of RUCO witness Tim Coley.

OPERATING INCOME ADJUSTMENTS

RUCO Operating Adjustment #1 – Labor Expense

Q. Has RUCO made an adjustment to the Company-proposed level of labor expense?

A. Yes.

Q. Please explain RUCO's adjustment to the Company-proposed level of labor expense.

A. During the Test Year, the Company incurred over 28,000 hours of overtime. This level of overtime is much higher than the levels of overtime hours that were recorded during the 2005, 2006 and 2008 operating periods. RUCO's adjustment normalizes overtime hours that were incurred during the Test Year (by using a four year average of overtime hours over the 2005 through 2008 operating periods) and reduces the Company's labor expense to reflect a more normal level of dollars paid for employee overtime. The adjustment is the first of four adjustments that affect all seventeen of AWC's operating systems. The other three related expenses include payroll tax expense, payroll 401(k) expense and insurance expense.

Q. What is the effect of RUCO's adjustment to labor expense?

A. RUCO's adjustment reduces labor expense by $302,000 on a total company basis. The adjustment involves all seventeen operating systems and is exhibited on Page 1 of Schedule WAR-9 for the Northern Group in my direct testimony and Page 2 of Schedule TJC-9 for the Eastern and Western Groups that are included in the direct testimony of RUCO witness Tim Coley.

RUCO Operating Adjustment #2 – Payroll Tax Expense

Q. Please explain RUCO's adjustment to the Company-proposed level of payroll tax expense.

A. This is the second of four adjustments related to the level of employee overtime incurred during the Test Year. The adjustment normalizes payroll tax expense associated with the excess overtime labor expense removed in RUCO Operating Expense Adjustment #1.

Q. What is the effect of RUCO's adjustment to payroll tax expense?

A. RUCO's adjustment reduces payroll tax expense by $32,967 on a total company basis. The adjustment affects all seventeen of AWC's operating systems and can be viewed on Page 2 of Schedule WAR-9 for the Northern Group systems and Page 2 of Schedule TJC-9 for the Eastern and Western Group systems.

RUCO Operating Adjustment #3 – Payroll 401(k) Expense

Q. Please explain RUCO's adjustment to the Company-proposed level of expense associated with AWC's 401(k) program.

A. The adjustment normalizes Company 401(k) retirement program contributions incurred during the Test year. As explained in the two prior adjustments, this is the third of four adjustments related to the level of employee overtime incurred during the Test Year.

Q. How does RUCO's adjustment affect the Company's test year adjusted 401(k) expense?

A. The adjustment reduces $401(k) expense associated by $25,282 on a total company basis. RUCO's adjustment affects all seventeen of AWC's operating systems and can be seen on Page 3 of Schedule WAR-9 for the Northern Group systems and Page 3 of Schedule TJC-9 for the Eastern and Western Group systems.

RUCO Operating Adjustment #4 – Reverse Adjustment for Conservation

Q. What adjustment has RUCO made to the Company-proposed level of administrative & general expense?

A. RUCO has reversed the Company's adjustment that increases administrative & general expense for the Northern Group by $308,701.

Q. What was the purpose of the Company's adjustment that increases administrative & general expense for the Northern Group by $308,701?

A. According to the Company's Application, the adjustment was designed to recover forecasted lost revenues as a result of implementing a water conservation-oriented, three-tiered inverted block rate design for the Northern group systems in this proceeding. The Northern group is presently the only group of systems that does not have inclining tiered rates.

Q. How did the Company arrive at the $308,701 figure?

A. According to the direct testimony of Company Witness Joel M. Reiker, a study of the Company's Western group was conducted following the implementation of tiered rates pursuant to Decision No. 68302. Mr. Reiker performed a regression analysis that holds average temperature and total precipitation conditions constant. Based on the results of the regression analysis, Mr. Reiker concludes that an 8.70 percent decrease in consumption will occur for every one million of gallons consumed.

Q. Why does RUCO disagree with the Company's adjustment?

A. RUCO does not believe a study that was performed on operating systems that are, for the most part, located in the central part of the state is relevant to the Northern Group. Although Mr. Reiker's study takes weather into consideration, there is no real guarantee that customers in the Northern group systems will react in the same way to tiered rates. Based on the Company's test year billing determinants, the average median consumption of 2,788 gallons for Northern Group residential customers was 3,780 gallons lower than the average median consumption of 6,658 for Western group residential customers. The lower level of consumption might indicate that Northern Group customers are already practicing conservation and may not be able to cut back on their usage. In any case, RUCO believes that the adjustment made by the Company is an

estimate at best that cannot predict with actual certainty how Northern Group ratepayers will react to the implementation of tired rates.

Q. Are you aware of a case where the Commission has adopted such an adjustment?

A. To the best of my knowledge no. I cannot say that I am aware of any case where the Commission adopted an adjustment that increased revenues as a result of conservation that might result from the implementation of either new rates or tiered rates. Recently, the Commission rejected a request by Southwest Gas Corporation for the implementation of a decoupling mechanism that, according to Southwest Gas Corporation, was designed to mitigate the effects of lost revenue due to ratepayer conservation.[2]

RUCO Operating Adjustment #5 – Purchased Power Revenues

Q. Please explain your Operating Adjustment #5 which reduces operating revenue for AWC's Northern Group by $39,446.

A. My adjustment reverses a Company pro forma adjustment that reflects changes in purchased power costs from base levels for the Northern Group. The adjustment for each of the five Northern Group systems can be viewed on Schedule WAR-8.

[2] Decision No. 70665, Dated December 24, 2008

Q. Why did the Company make this pro forma adjustment to increase Northern Group revenues?

A. According to AWC's Application, the Company made the pro forma adjustment to increase revenues collected through a PPAM which is currently in place in the Northern Group. As noted above, the revenues in question reflect changes in purchased power costs from base levels that were established in the most recent Northern Group rate case proceeding.[3] The Company is proposing that the PPAM be reset to zero with new base levels established in this proceeding at the current level of expense. The five Northern Group systems are the only AWC systems that presently have such a pass through mechanism.

Q. Why have you made this adjustment?

A. The adjustment is consistent with RUCO's recommendations to eliminate the Northern Group PPAM and to reject AWC's proposal to establish PPAM's for the Company's Eastern and Western Group systems.

Q. Why should the Company's Northern Group PPAM be eliminated?

A. RUCO believes that the elimination of the Northern Group PPAM is consistent with prior Commission orders that rejected AWC's proposals for PPAM's for the Eastern and Western Groups. RUCO believes that the Commission's conclusion in Decision No. 66849 – that the establishment

[3] Decision No. 64282, dated December 28, 2001

of a PPAM provides a disincentive for the Company to obtain the lowest possible cost commodity because the costs are simply passed through to ratepayers – is still valid. For this reason RUCO is recommending that the Northern Group PPAM be eliminated.

RUCO Operating Adjustment #6 – Insurance Expense

Q. What adjustment has RUCO made to the Company-proposed level of insurance expense?

A. RUCO has made a minor total company adjustment of $1,090 to the Company-proposed level of insurance expense. The adjustment is the last of four adjustments related to overtime pay that was recorded during the Test Year.

Q. What does RUCO's adjustment do?

A. The adjustment removes a portion of long-term disability insurance expense that is associated with the excess overtime labor expense removed in RUCO Operating Expense Adjustment #1. The adjustment affects all seventeen of AWC's operating systems and can be seen in Schedule WAR-10 for the Northern Group systems and Schedule TJC-10 for the Eastern and Western Group systems.

RUCO Operating Adjustment #7 – Depreciation Expense

Q. Have you recalculated Test Year depreciation and amortization expense?

A. Yes. Based on RUCO's adjusted test-year plant balances, I have recalculated depreciation and amortization expense on a going-forward basis. The adjustment is exhibited in Schedule WAR-11 for the Northern Group systems in my direct testimony and Schedule TJC-11 for the Eastern and Western Group systems that are included in the direct testimony of RUCO witness Tim Coley.

RUCO Operating Adjustment #8 – Property Tax Expense

Q. Has RUCO made an adjustment to the Company-proposed level of property tax expense?

A. Yes.

Q. Has RUCO calculated property tax expense using a methodology that has been adopted by the ACC in prior rate cases?

A. Yes. RUCO has used a modified version of the ADOR formula that has been adopted by the Commission in a number of prior rate cases. RUCO's calculation of property tax expense uses two years of adjusted operating revenues and one year of RUCO's recommended level of operating revenue to arrive at a three-year average of revenue that is subject to property tax. The calculation of property tax expense can be

viewed in Schedule WAR-12 for the Northern Group systems and Schedule TJC-12 for the Eastern and Western Group systems.

Q. Are there any differences between RUCO's calculation of property tax expense and the Company's calculation?

A. Yes. There are three differences. First, RUCO's calculation includes an addition of 10 percent of the amount of construction work in progress ("CWIP") that was booked during the Test Year. Second, RUCO has deducted the Test Year net book value of the Company's vehicles. Both of these items are required components of the ADOR formula. The third difference is the use of an updated assessment ratio of 22.5 percent which will be in effect at the time that AWC's new rates are approved by the Commission.

RUCO Operating Adjustment #9 – Rate Case Expense

Q. What level of rate case expense is AWC proposing?

A. AWC is proposing rate case expense, on a total company basis, of $500,000 to be amortized over a three-year period.

Q. What level of rate case expense is RUCO recommending?

A. RUCO is recommending a total company level of $300,000 dollars in rate case expense to be amortized over a three-year period.

Q. Is this RUCO's final recommended level of rate case expense?

A. No. This is RUCO's best estimate of rate case expense at this point in time. RUCO's estimate is based on information, provided by the Company, on total rate case expense that was billed just prior to the filing of RUCO's direct testimony. RUCO will update this figure and provide a final recommended level of rate case expense when it files final schedules after the evidentiary hearing on the instant case is concluded. The adjustment can be seen on Schedule WAR-13 for the Northern Group systems in my direct testimony and Schedule TJC-13 for the Eastern and Western Group systems that are included in the direct testimony of RUCO witness Tim Coley.

RUCO Operating Adjustment #10 – Income Tax Expense

Q. Have you calculated income tax expense based on RUCO's recommended adjusted operating income?

A. Yes. This adjustment is shown on Schedule WAR-14 for the Northern Group systems in my direct testimony and Schedule TJC-14 for the Eastern and Western Group systems that are included in the direct testimony of RUCO witness Tim Coley.

...

Q. Have you included an interest synchronization calculation in your computation of income tax expense?

A. Yes. The interest synchronization calculation, which computes an interest expense deduction for income taxes, can be viewed in the schedules noted above. The interest synchronization calculation is the adjusted rate base multiplied by the weighted cost of debt.

ADJUSTOR MECHANISMS

Q. What else is AWC requesting in this case besides an increase in operating revenue?

A. As noted earlier in my testimony, AWC is requesting the restoration of a PPAM for the Company's Eastern and Western Groups. The PPAM for the Eastern and Western Groups were eliminated by the Commission in Decisions on the prior rate cases for the Eastern and Western Groups. AWC is also asking that the Company be permitted to continue the PPAM that is currently in place for the Company's Northern Group. AWC is also requesting that the PWAM that the Commission eliminated in the prior Eastern and Western Group rate cases be restored. AWC is further requesting that a PFAM be established for all of the Company's operating systems in order to pass the costs of fuel through to ratepayers. Finally, AWC is asking for an AAM be implemented as an alternative to the aforementioned pass through mechanisms just described.

Q. Does RUCO support the restoration of any of the pass through mechanisms that AWC is seeking in this case?

A. No. RUCO does not support the implementation of any of the adjustor mechanisms being sought by AWC in this proceeding. As noted earlier in my testimony, RUCO is also recommending that the Northern Group PPAM be eliminated.

Q. Why is RUCO opposed to the company's request regarding adjustor mechanisms?

A. RUCO believes that the reasons given by the Commission for the elimination of the PPAM and PWAM in the prior rate cases are still valid. RUCO also believes that the Northern Group PPAM should also be eliminated for the same reasons that the Commission stated in the prior Eastern Group rate case. In Decision No. 66849, the Commission stated the following:

> "We agree with Staff that PPAM and PWAM adjustor mechanisms should be discontinued. Although Arizona Water argues that such mechanisms benefit both the Company and ratepayers by passing on increased costs and savings, adjustment mechanisms may also provide a disincentive for the Company to obtain the lowest possible cost commodity because the costs are simply passed through to ratepayers. Moreover, the record does not suggest that purchased power costs are a significant portion of the Company's expenses, the Superior system purchases only a small portion of its water supply and there is no evidence that the San Manuel system is expected to incur any significant increases or decreases in purchased water costs in the near future. Therefore, Arizona Water's purchased water adjustment mechanisms should be discontinued.

In the prior Western Group rate case, the Commission took the following position in Decision No. 68302:

> "There is a danger of piecemeal regulation inherent in adjustment mechanisms. Because they allow automatic increases in rates without a simultaneous review of a utility's unrelated costs, adjustment mechanisms have a built-in potential of allowing a utility to increase rates based on certain isolated costs when its other costs are declining, or when overall revenues are increasing faster than costs due to customer growth. Adjustment mechanisms should therefore be used only in extraordinary circumstances to mitigate the effect of uncontrollable price volatility or uncertainty in the marketplace. We have evaluated the propriety of continuing the Company's existing purchased water and purchased power adjustment mechanisms in the Western Group based on all relevant factors, including the APS Power Supply Adjustor. The evidence presented in this case does not support a finding that the Company's power and water supply costs are subject to a degree of price volatility or uncertainty that justifies the existence of its adjustment mechanisms, and we will therefore order that they be discontinued."

RUCO believes that the reasons stated in Decisions No.'s 66849 and 68302 apply also to the PFAM and AAM mechanisms that the Company is also seeking approval of in this proceeding.

Q. Has RUCO made any adjustments to the Company-proposed levels of purchased power, purchased water or fuel expense in this case?

A. No. RUCO has not made any adjustments to the Company-proposed levels of purchased power, purchased water or fuel expense.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of any of the witnesses for AWC constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on AWC?

A. Yes, it does.

Appendix 1

Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation
after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	W-01303A-07-0209	Rate Increase
Tucson Electric Power	E-01933A-07-0402	Rate Increase
Southwest Gas Corporation	G-01551A-07-0504	Rate Increase
Chaparral City Water Company	W-02113A-07-0551	Rate Increase
Arizona-American Water Company	W-01303A-08-0227 et al.	Rate Increase
Far West Water & Sewer Company	WS-03478A-08-0608	Interim Rate Increase
Johnson Utilities, LLC	WS-02987A-08-0180	Rate Increase
UNS Gas, Inc.	G-04204A-08-0571	Rate Increase

ARIZONA WATER COMPNAY

W-01445A-08-0440

NORTHERN OPERATING GROUP

Lakeside

Overgaard

Sedona

Pinewood

Rimrock

ARIZONA WATER COMPNAY

W-01445A-08-0440

Lakeside System

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Lakeside System

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WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-4 DIRECT PLANT	1 TO 7	RATE BASE ADJUSTMENT NO. 1 - PLANT & ACCUMULATED DEPRECIATION RECONCILIATION ADJUSTMENT
WAR-4 PHOENIX OFFICE	1 TO 5	RATE BASE ADJUSTMENT NO. 1 - PLANT & ACCUMULATED DEPRECIATION RECONCILIATION ADJUSTMENT
WAR-4 METER SHOP	1 TO 5	RATE BASE ADJUSTMENT NO. 1 - PLANT & ACCUMULATED DEPRECIATION RECONCILIATION ADJUSTMENT
WAR-5	1	RATE BASE ADJUSTMENT NO. 2 - REMOVE POST TEST-YEAR PLANT FOR PHOENIX OFFICE
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		RATE BASE ADJUSTMENT NO. 4 - INTENTIONALLY LEFT BLANK
		RATE BASE ADJUSTMENT NO. 5 - INTENTIONALLY LEFT BLANK
WAR-6	1 & 2	RATE BASE ADJUSTMENT NO. 6 - WORKING CAPITAL AND LEAD/LAG STUDY
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-9	1 OF 3	OPERATING INCOME ADJUSTMENT NO. 1 - PAYROLL EXPENSE
WAR-9	2 OF 3	OPERATING INCOME ADJUSTMENT NO. 2 - PAYROLL TAX EXPENSE RELATED TO PAYROLL EXPENSE ADJ. #1
WAR-9	3 OF 3	OPERATING INCOME ADJUSTMENT NO. 3 - 401(K) EXPENSE RELATED TO PAYROLL EXPENSE ADJ. #1
WAR-10	1	OPERATING INCOME ADJUSTMENT NO. 6 - INSURANCE EXPENSE
WAR-11	1	OPERATING INCOME ADJUSTMENT NO. 7 - TEST YEAR DEPRECIATION EXPENSE
WAR-12	1	OPERATING INCOME ADJUSTMENT NO. 8 - PROPERTY TAX COMPUTATION
WAR-13	1	OPERATING INCOME ADJUSTMENT NO. 9 - RATE CASE EXPENSE
WAR-14	1	OPERATING INCOME ADJUSTMENT NO. 10 - INCOME TAX EXPENSE
WAR-15	1	COST OF CAPITAL

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 7,169,218	$ 6,985,207
2	Adjusted Operating Income (Loss)	$ 517,717	$ 588,137
3	Current Rate of Return (L2 / L1)	7.22%	8.42%
4	Required Operating Income (L5 X L1)	$ 703,606	$ 545,431
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.81%
6	Operating Income Deficiency (L4 - L2)	$ 185,889	$ (42,706)
7	Gross Revenue Conversion Factor (WAR-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 302,745	$ (69,552)
9	Adjusted Test Year Revenue	$ 2,588,849	$ 2,553,472
10	Proposed Annual Revenue (L8 + L9)	$ 2,891,594	$ 2,483,919
11	Required Percentage Increase in Revenue (L8 / L9)	11.69%	-2.72%
12	Consolidated Revenue Adjustment (Lakeside/Overgaard)	$ (23,271)	$ -
13	Required Increase in Gross Revenue Under Company Proposed Consolidation	$ 279,355	$ -
14	Required Revenue Under Company Proposed Consolidation	$ 2,868,204	$ -
15	Required Percentage Increase in Revenue Under Company Proposed Consolidation	10.79%	-
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule WAR-2, WAR-7, and WAR-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. WAR-1, Pg 1, C (B), L4)	$ 545,431			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. WAR-1, Pg 1, C (B), L2)	588,137			
13	Required Increase In Operating Income (L11 - L12)		$ (42,706)		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 180,014			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	206,860			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ (26,846)		
17	Total Required Increase In Revenue (L13 + L16)		$ (69,552)		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. WAR-1, Pg 1, Col. (B), L12)			$ 2,483,919	
19	Operating Expense Excluding Income Tax (WAR-7, Col. (E), L27 - L22 - L23)			1,758,474	
20	Synchronized Interest (Col. (C), L37)			259,075	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 466,370	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 32,497
24	Fed. Taxable Income (L21 - L23)			$ 433,873	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ 6,250	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ 8,500	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ 91,650	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 33,617	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 147,517
31	Combined Federal and State Income Tax (L23 + L30)				$ 180,014
32	Test Year Combined Income Tax, RUCO as Adjusted (WAR-7, Col. (C), L22 + L23)				$ 206,860
33	RUCO Adjustment (L31 - L32) (See WAR-6, Col. (D), L23)				$ (26,846)
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 6,985,207	
36	Weighted Avg. Cost of Debt (Sch. WAR-16, Col. (F), L1)			3.71%	
37	Synchronized Interest (L35 X L36)			$ 259,075	

Arizona Water Company
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Test Year Ended December 31, 2007

Lakeside System
Schedule WAR-2

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 1,767	$ -	$ 1,767
2	Source of Supply Plant	1,730,757	(313,824)	1,416,933
3	Pumping Plant	2,184,518	-	2,184,518
4	Water Treatment Plant	72,344	-	72,344
5	Transmission & Distribution Plant	11,151,870	-	11,151,870
6	General Plant	903,362	(7,444)	895,919
7	Total Gross Plant in Service	$ 16,044,619	$ (321,268)	$ 15,723,352
8	Accumulated Depreciation	(4,088,030)	209,297	(3,878,733)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 11,956,589	$ (111,970)	$ 11,844,619
10	Advances In Aid Of Const.	$ (2,366,968)	$ -	$ (2,366,968)
11	Contribution In Aid of Const.	$ (1,691,940)	$ -	$ (1,691,940)
12	Accumulated Amortization of CIAC	370,501	-	370,501
13	NET CIAC (L5 + L6)	$ (1,321,439)	$ -	$ (1,321,439)
14	Deferred Income Tax	$ (1,188,230)	$ -	$ (1,188,230)
15	Allowance for Working Capital	$ 89,266	$ (72,041)	$ 17,225
16	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
17	Rounding	$ -	$ -	$ -
18	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 7,169,218	$ (184,011)	$ 6,985,207

References:
Column (A): Company Schedule B-1
Column (B): Schedule WAR-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2 REMOVE PTY PLANT	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 1,767	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,767
2	Source of Supply Plant	1,730,757	-	-	(313,824)	-	-	-	1,416,933
3	Pumping Plant	2,184,518	-	-	-	-	-	-	2,184,518
4	Water Treatment Plant	72,344	-	-	-	-	-	-	72,344
5	Transmission & Distribution Plant	11,151,870	-	-	-	-	-	-	11,151,870
6	General Plant	903,362	-	(7,444)	-	-	-	-	895,919
7	Total Gross Plant in Service	$ 16,044,619	$ -	$ (7,444)	$ (313,824)	$ -	$ -	$ -	$ 15,723,352
8	Accumulated Depreciation	$ (4,088,030)	1,784	248	207,265	-	-	-	(3,878,733)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 11,956,589	$ 1,784	$ (7,195)	$ (106,559)	$ -	$ -	$ -	$ 11,844,619
10	Advances In Aid Of Const.	$ (2,366,968)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,366,968)
11	Contribution In Aid of Const.	$ (1,691,940)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,691,940)
12	Accumulated Amortization of CIAC	370,501	-	-	-	-	-	-	370,501
13	NET CIAC (L5 + L6)	$ (1,321,439)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,321,439)
14	Deferred Income Tax	$ (1,188,230)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,188,230)
15	Allowance for Working Capital	$ 89,266	$ -	$ -	$ -	$ -	$ -	$ (72,041)	$ 17,225
16	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Rounding	$ -							$ -
18	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 7,169,218	$ 1,784	$ (7,195)	$ (106,559)	$ -	$ -	$ (72,041)	$ 6,985,207

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See WAR-4 Total, WAR-4 Direct, WAR-4 PHX OFF and WAR-4 MS Schedules and WAR Testimc
Column (C): Adjustment No. 2 - To Remove Post Test Year Phoenix Office Plant and Accum. Depre.
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Intentionally Left Blank
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) Decision 64282 1/1/2002 To Present	(C) 12/31/1999 Per Decision No. 64282	(D) ADJ-1 Remove Post Test Year Plant	(E) Plant Balance 12/31/1999
1	301	Organization	0.00%	0.00%	-	$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111	-	-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111	-	-	-
4	310.1	Water Rights	0.00%	0.00%	104,579	-	104,579
5	310.3	Other Source of Supply Land	0.00%	0.00%	14,332	-	14,332
6	310.4	Wells - Other	See Acct. 111	See Acct. 111	-	-	-
7	314	Wells	2.59%	2.59%	835,546	-	835,546
8	320	Pumping Plant Land	0.00%	0.00%	7,953	-	7,953
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	73,067	-	73,067
10	325	Electtric Pumping Equipment	2.59%	2.59%	1,234,087	-	1,234,087
11	328	Gas Engine Equipment	2.59%	2.59%	-	-	-
12	330	Water Treatment Plant Land	0.00%	0.00%	-	-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	-	-	-
14	332	Water Treatment Equipment	2.59%	2.59%	61,560	-	61,560
15	340	Transmission and Distribution Land	0.00%	0.00%	23,558	-	23,558
16	342	Storage Tanks	2.59%	2.59%	651,690	-	651,690
17	343	Transmission & Distribution Mains	2.59%	2.59%	4,105,586	-	4,105,586
18	344	Fire Sprinkler Taps	2.59%	2.59%	25,108	-	25,108
19	345	Services	2.59%	2.59%	1,538,340	-	1,538,340
20	346	Meters	2.59%	2.59%	231,495	-	231,495
21	348	Hydrants	2.59%	2.59%	279,351	-	279,351
22	389	General Plant Land	0.00%	0.00%	1,800	-	1,800
23	390	General Plant Structures	2.59%	2.59%	80,729	-	80,729
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	8,123	-	8,123
25	391	Office Furniture & Equipment	2.59%	2.59%	87,850	-	87,850
26	393	Warehouse Equipment	2.59%	2.59%	3,512	-	3,512
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	52,925	-	52,925
28	395	Laboratory Equipment	2.59%	2.59%	393	-	393
29	396	Power Operated Equipment	2.59%	2.59%	4,022	-	4,022
30	397	Communication Equipment	2.59%	2.59%	83,745	-	83,745
31	398	Miscellaneous Equipment	2.59%	2.59%	16,351	-	16,351
32		**TOTAL DIRECT WATER PLANT**			$ 9,525,702	$ -	$ 9,525,702
33		Post Test Year Plant (PTYP)			239,366	(239,366)	-
34		**RUCO Total Water Plant In Service**			$ 9,765,068	$ (239,366)	$ 9,525,702
35							
36		**Company Direct Plant As Filed**					
37							
38		**RUCO Direct Plant Adjustment**					
39							
40		Reserve Deficiency Accrual - Decision No. 38733					
41							
42		Net (Salvage)/Cost of Removal					
43		Accumulated Depreciation			(1,916,445)		$ (1,916,445)
44		Accumulated Depreciation - PTYP			(227,436)	227,436	-
45		RUCO Total Accumulated Depreciation - Calculated			$ (2,143,881)		$ (1,916,445)
46							
47		Company As Filed - Accumulated Depreciation			-	-	(1,916,445)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ (2,143,881)	$ -	$ -
49							
50		**RUCO Net Adjustment**					
51							
52							
53							

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2000 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2000
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	4,034			-	108,613
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	14,332
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				21,641	835,546
8	320	Pumping Plant Land	0.00%	0.00%				-	7,953
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	931			1,904	73,998
10	325	Electtric Pumping Equipment	2.59%	2.59%	97,360	(47,830)		32,604	1,283,618
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				-	-
14	332	Water Treatment Equipment	2.59%	2.59%	969			1,607	62,529
15	340	Transmission and Distribution Land	0.00%	0.00%				-	23,558
16	342	Storage Tanks	2.59%	2.59%	311			16,883	652,001
17	343	Transmission & Distribution Mains	2.59%	2.59%	151,262	(6,573)	(11,501)	108,059	4,238,775
18	344	Fire Sprinkler Taps	2.59%	2.59%	6,636			736	31,744
19	345	Services	2.59%	2.59%	103,878	(729)		41,179	1,641,489
20	346	Meters	2.59%	2.59%	16,153	(8,282)		6,098	239,366
21	348	Hydrants	2.59%	2.59%	39,509	(1,091)		7,733	317,770
22	389	General Plant Land	0.00%	0.00%				-	1,800
23	390	General Plant Structures	2.59%	2.59%				2,091	80,729
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	64			2,323	8,187
25	391	Office Furniture & Equipment	2.59%	2.59%	12,794			2,441	100,644
26	393	Warehouse Equipment	2.59%	2.59%				91	3,512
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	4,624	(3,773)		1,382	53,777
28	395	Laboratory Equipment	2.59%	2.59%				10	393
29	396	Power Operated Equipment	2.59%	2.59%				104	4,022
30	397	Communication Equipment	2.59%	2.59%	10,093			2,300	93,838
31	398	Miscellaneous Equipment	2.59%	2.59%	2,829			460	19,180
32		**TOTAL DIRECT WATER PLANT**			$ 451,447	$ (68,277)	$ (11,501)	$ 249,646	$ 9,897,371
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 451,447	$ (68,277)	$ (11,501)	$ 249,646	$ 9,897,371
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(31)	
41									
42		Net (Salvage)/Cost of Removal						1,310	
43		Accumulated Depreciation						(2,096,535)	$ (2,096,535)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(2,096,535)	$ (2,096,535)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,096,891)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,096,535)	$ 356
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other Intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2001 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2001
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	3,683			-	112,296
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	14,332
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	646,007			30,006	1,481,553
8	320	Pumping Plant Land	0.00%	0.00%				-	7,953
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	20,019	(582)		2,168	93,435
10	325	Electtric Pumping Equipment	2.59%	2.59%	173,131			35,488	1,456,749
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	262			3	262
14	332	Water Treatment Equipment	2.59%	2.59%	2,741			1,655	65,270
15	340	Transmission and Distribution Land	0.00%	0.00%				-	23,558
16	342	Storage Tanks	2.59%	2.59%	2,093			16,914	654,094
17	343	Transmission & Distribution Mains	2.59%	2.59%	612,165	(13,202)		117,541	4,837,738
18	344	Fire Sprinkler Taps	2.59%	2.59%	12,356			982	44,099
19	345	Services	2.59%	2.59%	169,870	(4,956)		44,650	1,806,403
20	346	Meters	2.59%	2.59%	12,300	(2,160)		6,331	249,506
21	348	Hydrants	2.59%	2.59%	57,070	(5,356)		8,900	369,484
22	389	General Plant Land	0.00%	0.00%				-	1,800
23	390	General Plant Structures	2.59%	2.59%	2,508			2,123	83,237
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	11,755			3,073	19,941
25	391	Office Furniture & Equipment	2.59%	2.59%	5,014	(1,732)		2,649	103,925
26	393	Warehouse Equipment	2.59%	2.59%				91	3,512
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	375	(6,000)		1,320	48,152
28	395	Laboratory Equipment	2.59%	2.59%				10	393
29	396	Power Operated Equipment	2.59%	2.59%				104	4,022
30	397	Communication Equipment	2.59%	2.59%	4,673			2,491	98,510
31	398	Miscellaneous Equipment	2.59%	2.59%	738			506	19,919
32		**TOTAL DIRECT WATER PLANT**			$ 1,736,760	$ (33,988)	$ -	$ 277,007	$ 11,600,143
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 1,736,760	$ (33,988)	$ -	$ 277,007	$ 11,600,143
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(31)	
41									
42		Net (Salvage)/Cost of Removal						(1,200)	
43		Accumulated Depreciation						(2,340,785)	$ (2,340,785)
44		Accumulated Depreciation - PTYP						-	$ -
45		RUCO Total Accumulated Depreciation - Calculated						(2,340,785)	$ (2,340,785)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,341,391)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,340,785)	$ 606
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2002 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2002
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	16,295			-	128,591
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	14,332
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	969			38,385	1,482,522
8	320	Pumping Plant Land	0.00%	0.00%				-	7,953
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	243			2,423	93,678
10	325	Electtric Pumping Equipment	2.59%	2.59%	10,504			37,866	1,467,253
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				7	262
14	332	Water Treatment Equipment	2.59%	2.59%	432			1,696	65,702
15	340	Transmission and Distribution Land	0.00%	0.00%				-	23,558
16	342	Storage Tanks	2.59%	2.59%	1,152			16,956	655,246
17	343	Transmission & Distribution Mains	2.59%	2.59%	389,638	(5,645)	(1,137)	130,255	5,220,594
18	344	Fire Sprinkler Taps	2.59%	2.59%	1,060			1,156	45,160
19	345	Services	2.59%	2.59%	183,494	(466)		49,156	1,989,430
20	346	Meters	2.59%	2.59%	16,770	(2,775)		6,643	263,501
21	348	Hydrants	2.59%	2.59%	57,511	(2,553)		10,281	424,442
22	389	General Plant Land	0.00%	0.00%	195			-	1,995
23	390	General Plant Structures	2.59%	2.59%				2,156	83,237
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	7,000			10,478	26,941
25	391	Office Furniture & Equipment	2.59%	2.59%	5,170			2,759	109,095
26	393	Warehouse Equipment	2.59%	2.59%				91	3,512
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	937	(403)		1,254	48,686
28	395	Laboratory Equipment	2.59%	2.59%				10	393
29	396	Power Operated Equipment	2.59%	2.59%				104	4,022
30	397	Communication Equipment	2.59%	2.59%	15,411			2,751	113,921
31	398	Miscellaneous Equipment	2.59%	2.59%	720			525	20,639
32		**TOTAL DIRECT WATER PLANT**			$ 707,501	$ (11,842)	$ (1,137)	$ 314,953	$ 12,294,665
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 707,501	$ (11,842)	$ (1,137)	$ 314,953	$ 12,294,665
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(31)	
41									
42		Net (Salvage)/Cost of Removal						3,239	
43		Accumulated Depreciation						(2,640,687)	$ (2,640,687)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(2,640,687)	(2,640,687)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,642,568)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,640,687)	$ 1,881
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
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LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2003 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2003
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	11,294			-	139,885
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	14,332
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	3,215			38,439	1,485,738
8	320	Pumping Plant Land	0.00%	0.00%				-	7,953
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	6,947			2,516	100,625
10	325	Electtric Pumping Equipment	2.59%	2.59%	275,484	(162,799)		39,461	1,579,937
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				7	262
14	332	Water Treatment Equipment	2.59%	2.59%	1,787			1,725	67,489
15	340	Transmission and Distribution Land	0.00%	0.00%				-	23,558
16	342	Storage Tanks	2.59%	2.59%	14,865			17,163	670,111
17	343	Transmission & Distribution Mains	2.59%	2.59%	582,056	(4,031)		142,699	5,798,619
18	344	Fire Sprinkler Taps	2.59%	2.59%	5,953			1,247	51,112
19	345	Services	2.59%	2.59%	172,044	(3,095)		53,714	2,158,379
20	346	Meters	2.59%	2.59%	16,536	(1,658)		7,017	278,378
21	348	Hydrants	2.59%	2.59%	85,311	(2,983)		12,059	506,771
22	389	General Plant Land	0.00%	0.00%				-	1,995
23	390	General Plant Structures	2.59%	2.59%				2,156	83,237
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	5,564			1,575	32,506
25	391	Office Furniture & Equipment	2.59%	2.59%	1,257			2,842	110,352
26	393	Warehouse Equipment	2.59%	2.59%				91	3,512
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	2,927	(1,410)		1,281	50,203
28	395	Laboratory Equipment	2.59%	2.59%				10	393
29	396	Power Operated Equipment	2.59%	2.59%				104	4,022
30	397	Communication Equipment	2.59%	2.59%	7,936			3,053	121,857
31	398	Miscellaneous Equipment	2.59%	2.59%	1,878			559	22,517
32		**TOTAL DIRECT WATER PLANT**			$ 1,195,054	$ (175,976)	$ -	$ 327,718	$ 13,313,743
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 1,195,054	$ (175,976)	$ -	$ 327,718	$ 13,313,743
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(31)	
41									
42		Net (Salvage)/Cost of Removal						(451)	
43		Accumulated Depreciation						(2,792,911)	$ (2,792,911)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(2,792,911)	(2,792,911)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,794,792)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,792,911)	$ 1,881
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other Intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
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Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111	1,386			-	1,386
4	310.1	Water Rights	0.00%	0.00%	6,323			-	146,208
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	14,332
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	1,102			38,495	1,486,839
8	320	Pumping Plant Land	0.00%	0.00%				-	7,953
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	2,328			2,636	102,953
10	325	Electtric Pumping Equipment	2.59%	2.59%	138,175	(149,841)		40,769	1,568,271
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				7	262
14	332	Water Treatment Equipment	2.59%	2.59%	1,244			1,764	68,733
15	340	Transmission and Distribution Land	0.00%	0.00%				-	23,558
16	342	Storage Tanks	2.59%	2.59%	1,716			17,378	671,827
17	343	Transmission & Distribution Mains	2.59%	2.59%	249,919	(4,252)		153,366	6,044,286
18	344	Fire Sprinkler Taps	2.59%	2.59%	9,834			1,451	60,946
19	345	Services	2.59%	2.59%	63,871	(3,731)		56,681	2,218,519
20	346	Meters	2.59%	2.59%	11,749	(415)		7,357	289,712
21	348	Hydrants	2.59%	2.59%	22,025	(919)		13,399	527,877
22	389	General Plant Land	0.00%	0.00%	50			-	2,045
23	390	General Plant Structures	2.59%	2.59%	1,313			2,173	84,549
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	4,496			3,061	37,002
25	391	Office Furniture & Equipment	2.59%	2.59%	5,633			2,931	115,985
26	393	Warehouse Equipment	2.59%	2.59%				91	3,512
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	6,958	(4,301)		1,335	52,860
28	395	Laboratory Equipment	2.59%	2.59%				10	393
29	396	Power Operated Equipment	2.59%	2.59%	797			114	4,819
30	397	Communication Equipment	2.59%	2.59%	2,639	(1,738)		3,168	122,758
31	398	Miscellaneous Equipment	2.59%	2.59%	1,921			608	24,438
32		**TOTAL DIRECT WATER PLANT**			$ 533,478	$ (165,197)	$ -	$ 346,794	$ 13,682,024
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 533,478	$ (165,197)	$ -	$ 346,794	$ 13,682,024
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(31)	
41									
42		Net (Salvage)/Cost of Removal						(28)	
43		Accumulated Depreciation						(2,974,567)	$ (2,974,567)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(2,974,567)	(2,974,567)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,976,447)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,974,567)	$ 1,880
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
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Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111			(186)	-	1,200
4	310.1	Water Rights	0.00%	0.00%	12,932			-	159,140
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	14,332
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	772			38,519	1,487,611
8	320	Pumping Plant Land	0.00%	0.00%				-	7,953
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	861			2,678	103,815
10	325	Electtric Pumping Equipment	2.59%	2.59%	195,028	(2,164)		43,116	1,761,135
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				7	262
14	332	Water Treatment Equipment	2.59%	2.59%	1,115			1,795	69,848
15	340	Transmission and Distribution Land	0.00%	0.00%				-	23,558
16	342	Storage Tanks	2.59%	2.59%				17,400	671,827
17	343	Transmission & Distribution Mains	2.59%	2.59%	391,703	(6,804)		161,531	6,429,185
18	344	Fire Sprinkler Taps	2.59%	2.59%	14,932			1,772	75,878
19	345	Services	2.59%	2.59%	149,295	(2,245)		59,364	2,365,570
20	346	Meters	2.59%	2.59%	15,875	(376)		7,704	305,211
21	348	Hydrants	2.59%	2.59%	48,898			14,305	576,775
22	389	General Plant Land	0.00%	0.00%			(50)	-	1,995
23	390	General Plant Structures	2.59%	2.59%	1,310			2,207	85,859
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	5,335			4,766	42,336
25	391	Office Furniture & Equipment	2.59%	2.59%	893			3,016	116,878
26	393	Warehouse Equipment	2.59%	2.59%				91	3,512
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	55			1,370	52,915
28	395	Laboratory Equipment	2.59%	2.59%				10	393
29	396	Power Operated Equipment	2.59%	2.59%				125	4,819
30	397	Communication Equipment	2.59%	2.59%	5,613			3,252	128,371
31	398	Miscellaneous Equipment	2.59%	2.59%				633	24,438
32		**TOTAL DIRECT WATER PLANT**			$ 844,617	$ (11,589)	$ (237)	$ 363,660	$ 14,514,815
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 844,617	$ (11,589)	$ (237)	$ 363,660	$ 14,514,815
35									-
36		**Company Direct Plant As Filed**							
37									$ 14,514,815
38		**RUCO Direct Plant Adjustment**							
39								(31)	
40		Reserve Deficiency Accrual - Decision No. 38733							
41								-	
42		Net (Salvage)/Cost of Removal						(3,326,669)	$ (3,326,669)
43		Accumulated Depreciation						-	-
44		Accumulated Depreciation - PTYP						(3,326,669)	(3,326,669)
45		RUCO Total Accumulated Depreciation - Calculated							
46					-	-	-	-	(3,328,549)
47		Company As Filed - Accumulated Depreciation			$ -	$ -	$ -	$ (3,326,669)	$ 1,880
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**							
49									$ 14,516,695
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	1,200
4	310.1	Water Rights	0.00%	0.00%	15,842			-	174,982
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	14,332
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	4,428			38,586	1,492,039
8	320	Pumping Plant Land	0.00%	0.00%				-	7,953
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	7,779	(1,575)		2,769	110,019
10	325	Electtric Pumping Equipment	2.59%	2.59%	118,120	(69,587)		46,242	1,809,668
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	135			9	397
14	332	Water Treatment Equipment	2.59%	2.59%	540			1,816	70,388
15	340	Transmission and Distribution Land	0.00%	0.00%				-	23,558
16	342	Storage Tanks	2.59%	2.59%				17,400	671,827
17	343	Transmission & Distribution Mains	2.59%	2.59%	150,207	(1,520)		168,441	6,577,873
18	344	Fire Sprinkler Taps	2.59%	2.59%	3,287			2,008	79,165
19	345	Services	2.59%	2.59%	79,204	(1,810)		62,271	2,442,964
20	346	Meters	2.59%	2.59%	14,426	(168)		8,090	319,469
21	348	Hydrants	2.59%	2.59%	14,351			15,124	591,126
22	389	General Plant Land	0.00%	0.00%				-	1,995
23	390	General Plant Structures	2.59%	2.59%				2,224	85,859
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	11,863			7,067	54,199
25	391	Office Furniture & Equipment	2.59%	2.59%	7,282			3,121	124,160
26	393	Warehouse Equipment	2.59%	2.59%				91	3,512
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	909			1,382	53,823
28	395	Laboratory Equipment	2.59%	2.59%				10	393
29	396	Power Operated Equipment	2.59%	2.59%				125	4,819
30	397	Communication Equipment	2.59%	2.59%	2,981			3,363	131,352
31	398	Miscellaneous Equipment	2.59%	2.59%				633	24,438
32		**TOTAL DIRECT WATER PLANT**			$ 431,354	$ (74,660)	$ -	$ 380,773	$ 14,871,509
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 431,354	$ (74,660)	$ -	$ 380,773	$ 14,871,509
35									
36		**Company Direct Plant As Filed**							-
37									
38		**RUCO Direct Plant Adjustment**							$ 14,871,509
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						(112)	
43		Accumulated Depreciation						(3,632,894)	$ (3,632,894)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(3,632,894)	(3,632,894)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(3,634,774)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (3,632,894)	$ 1,880
49									
50		**RUCO Net Adjustment**							$ 14,873,390
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				60	1,200
4	310.1	Water Rights	0.00%	0.00%	45,876			-	220,858
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	14,332
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	3,522			38,689	1,495,561
8	320	Pumping Plant Land	0.00%	0.00%				-	7,953
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	128			2,851	110,147
10	325	Electric Pumping Equipment	2.59%	2.59%	256,751			50,195	2,066,419
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				10	397
14	332	Water Treatment Equipment	2.59%	2.59%	1,433			1,842	71,820
15	340	Transmission and Distribution Land	0.00%	0.00%				-	23,558
16	342	Storage Tanks	2.59%	2.59%	1,185			17,416	673,012
17	343	Transmission & Distribution Mains	2.59%	2.59%	335,830	(2,127)		174,688	6,911,575
18	344	Fire Sprinkler Taps	2.59%	2.59%				2,050	79,165
19	345	Services	2.59%	2.59%	85,767	(725)		64,374	2,528,006
20	346	Meters	2.59%	2.59%	5,997	(152)		8,350	325,314
21	348	Hydrants	2.59%	2.59%	21,364	(1,627)		15,566	610,863
22	389	General Plant Land	0.00%	0.00%				-	1,995
23	390	General Plant Structures	2.59%	2.59%	12,627			2,387	98,486
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	347			3,093	54,546
25	391	Office Furniture & Equipment	2.59%	2.59%	8,017			3,320	132,178
26	393	Warehouse Equipment	2.59%	2.59%				91	3,512
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	3,871			1,444	57,694
28	395	Laboratory Equipment	2.59%	2.59%				10	393
29	396	Power Operated Equipment	2.59%	2.59%				125	4,819
30	397	Communication Equipment	2.59%	2.59%	4,715			3,463	136,067
31	398	Miscellaneous Equipment	2.59%	2.59%				633	24,438
32		**TOTAL DIRECT WATER PLANT**			$ 787,429	$ (4,631)	$ -	$ 390,658	$ 15,654,307
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 787,429	$ (4,631)	$ -	$ 390,658	$ 15,654,307
35									
36		**Company Direct Plant As Filed**							15,654,309
37									
38		**RUCO Direct Plant Adjustment**							$ (2)
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						-	
43		Accumulated Depreciation						(4,018,921)	$ (4,018,921)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(4,018,921)	(4,018,921)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(4,020,801)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (4,018,921)	$ 1,880
49									
50		**RUCO Net Adjustment**							$ 1,879
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other Intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2003 12/31/2003 Per Decision 68302	2003 ADJ-1 Remove Post Test Year Plant	2003 Balance 12/31/2003
1	301	Organization	0.00%	651		651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.	8,496		8,496
4	310.1	Water Rights	0.00%	-		-
5	310.3	Other Source of Supply Land	0.00%	-		-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
7	314	Wells	2.59%	-		-
8	320	Pumping Plant Land	0.00%	-		-
9	321	Pumping Plant Structures and Improvements	2.59%	-		-
10	325	Electric Pumping Equipment	2.59%	-		-
11	328	Gas Engine Equipment	2.59%	-		-
12	330	Water Treatment Plant Land	0.00%	-		-
13	331	Water Treatment Structures and Improvements	2.59%	-		-
14	332	Water Treatment Equipment	2.59%	-		-
15	340	Transmission and Distribution Land	0.00%	-		-
16	342	Storage Tanks	2.59%	-		-
17	343	Transmission and Distribution Mains	2.59%	-		-
18	344	Fire Sprinkler Taps	2.59%	-		-
19	345	Services	2.59%	-		-
20	346	Meters	2.59%	-		-
21	348	Hydrants	2.59%	-		-
22	389	General Plant Land	0.00%	-		-
23	390	General Plant Structures	2.59%	31,795		31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	1,267,373		1,267,373
25	391	Office Furniture and Equipment	2.59%	3,505,411		3,505,411
26	393	Warehouse Equipment	2.59%	3,705		3,705
27	394	Tools, Shop and Garage Equipment	2.59%	30,450		30,450
28	395	Laboratory Equipment	2.59%	977		977
29	396	Power Operated Equipment	2.59%	-		-
30	397	Communication Equipment	2.59%	143,052		143,052
31	398	Miscellaneous Equipment	2.59%	7,207		7,207
32		**TOTAL PHOENIX OFFICE PLANT**		4,999,117	-	4,999,117
33		Post Test Year Plant (PTYP)		-	-	-
34		**RUCO Total Phoenix Office**		4,999,117	-	4,999,117
35						
36		**Company Phoenix Office As Filed**		4,999,117		4,999,117
37						
38		RUCO Phoenix Office Plant Adjustment		-		-
39						
40		Reserve Deficiency Accrual - Dec. 38733		-		-
41						
42		Net (Salvage)/Cost of Removal				
43		Accumulated Depreciation		(503,775)	-	(503,775)
44		Accumulated Depreciation - PTYP		-	-	-
45		RUCO Total Accumulated Depreciation - Calculated		(503,775)	-	(503,775)
46						
47		Company As Filed - Accumulated Depreciation				(503,775)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**				-
49						
50		**RUCO Net Adjustment**				
51						
52						
53						
54						
55						

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
			Dec. 58120 1/1/1993 To Present					
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	48,512			78,228	1,315,885
25	391	Office Furniture and Equipment	2.59%	129,135	(7,465)		92,366	3,627,081
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	24,820			1,110	55,270
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	6,465			3,789	149,517
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		208,932	(7,465)	-	176,624	5,200,584
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,200,584
35								
36		**Company Phoenix Office As Filed**						5,200,584
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(672,934)	(672,934)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(672,934)	(672,934)
46								
47		Company As Filed - Accumulated Depreciation						(672,934)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(0)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
			Dec. 58120 1/1/1993 To Present					
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				823	31,795
23	390	General Plant Structures	2.59%				89,580	1,315,885
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				96,808	3,848,420
25	391	Office Furniture and Equipment	2.59%	221,339			96	3,705
26	393	Warehouse Equipment	2.59%				1,698	75,855
27	394	Tools, Shop and Garage Equipment	2.59%	20,585			25	977
28	395	Laboratory Equipment	2.59%				-	-
29	396	Power Operated Equipment	2.59%				3,884	150,402
30	397	Communication Equipment	2.59%	885			187	7,207
31	398	Miscellaneous Equipment	2.59%					
32		**TOTAL PHOENIX OFFICE PLANT**		242,809	-	-	193,101	5,443,393
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,443,393
35								
36		**Company Phoenix Office As Filed**						5,443,393
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41							-	
42		Net (Salvage)/Cost of Removal					(866,035)	(866,035)
43		Accumulated Depreciation					-	-
44		Accumulated Depreciation - PTYP					(866,035)	(866,035)
45		RUCO Total Accumulated Depreciation - Calculated						
46								(866,035)
47		Company As Filed - Accumulated Depreciation						0
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				94,864	1,315,885
25	391	Office Furniture and Equipment	2.59%	369,071			104,454	4,217,491
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	59,519			2,735	135,374
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	1,741			3,918	152,143
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		430,332	-	-	207,102	5,873,725
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,873,725
35								
36		**Company Phoenix Office As Filed**						5,873,725
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(1,073,138)	(1,073,138)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(1,073,138)	(1,073,138)
46								
47		Company As Filed - Accumulated Depreciation						(1,073,137)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(1)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				425	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	10,463			959	42,258
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	93			86,708	1,315,978
25	391	Office Furniture and Equipment	2.59%	464,535	(243,714)		112,093	4,438,312
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	40,312			4,028	175,686
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	4,089			3,993	156,232
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		519,493	(243,714)	-	208,514	6,149,503
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						6,149,503
35								
36		**Company Phoenix Office As Filed**						6,029,446
37								
38		RUCO Phoenix Office Plant Adjustment						120,057
39							-	
40		Reserve Deficiency Accrual - Dec. 38733						
41							-	
42		Net (Salvage)/Cost of Removal					(1,037,938)	(1,037,938)
43		Accumulated Depreciation					-	-
44		Accumulated Depreciation - PTYP					(1,037,938)	(1,037,938)
45		RUCO Total Accumulated Depreciation - Calculated						
46								(1,036,382)
47		Company As Filed - Accumulated Depreciation						(1,556)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						
49								118,501
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2003 12/31/2003 Per Decision 68302	2003 ADJ-1 Remove Post Test Year Plant	2003 Balance 12/31/2003
1	301	Organization	0.00%	-		-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
4	310.1	Water Rights	0.00%	-		-
5	310.3	Other Source of Supply Land	0.00%	80		80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
7	314	Wells	2.59%	-		-
8	320	Pumping Plant Land	0.00%	-		-
9	321	Pumping Plant Structures and Improvements	2.59%	-		-
10	325	Electric Pumping Equipment	2.59%	-		-
11	328	Gas Engine Equipment	2.59%	-		-
12	330	Water Treatment Plant Land	0.00%	-		-
13	331	Water Treatment Structures and Improvements	2.59%	-		-
14	332	Water Treatment Equipment	2.59%	2,050		2,050
15	340	Transmission and Distribution Land	0.00%	-		-
16	342	Storage Tanks	2.59%	-		-
17	343	Transmission and Distribution Mains	2.59%	6,066		6,066
18	344	Fire Sprinkler Taps	2.59%	-		-
19	345	Services	2.59%	-		-
20	346	Meters	2.59%	-		-
21	348	Hydrants	2.59%	-		-
22	389	General Plant Land	0.00%	-		-
23	390	General Plant Structures	2.59%	37,472		37,472
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	-		-
25	391	Office Furniture and Equipment	2.59%	3,983		3,983
26	393	Warehouse Equipment	2.59%	1,088		1,088
27	394	Tools, Shop and Garage Equipment	2.59%	58,430		58,430
28	395	Laboratory Equipment	2.59%	2,981		2,981
29	396	Power Operated Equipment	2.59%	1,458		1,458
30	397	Communication Equipment	2.59%	-		-
31	398	Miscellaneous Equipment	2.59%	-		-
32		**TOTAL METER SHOP PLANT**		113,608	-	113,608
33		Post Test Year Plant (PTYP)		-	-	-
34		**RUCO Total Meter Shop**		113,608	-	113,608
35						
36		**Company Meter Shop As Filed**		113,608		113,608
37						
38		RUCO Meter Shop Plant Adjustment		-		-
39						
40		Reserve Deficiency Accrual - Dec. 38733				
41						
42		Net (Salvage)/Cost of Removal		(30,118)	-	(30,118)
43		Accumulated Depreciation		-	-	-
44		Accumulated Depreciation - PTYP		(30,118)	-	(30,118)
45		RUCO Total Accumulated Depreciation - Calculated				
46						
47		Company As Filed - Accumulated Depreciation				(30,118)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**				-
49						
50		**RUCO Net Adjustment**				
51						
52						
53						
54						
55						
56		Notes				
57		Acct. 302 - Franchises amortized over 25 years.				
58		Acct. 303 - Other intangibles amortized over 15 & 20 Years.				
59		Acct. 310.4 - Wells - Other amortized over 24 years.				
60		Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.				

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	80
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				53	2,050
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				157	6,066
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	12,809			1,136	50,281
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr				-	-
25	391	Office Furniture and Equipment	2.59%	3,166			144	7,149
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	1,575			1,534	60,005
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		17,550	-	-	3,168	131,158
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						131,158
35								131,158
36		**Company Meter Shop As Filed**						
37								-
38		RUCO Meter Shop Plant Adjustment						
39								
40		Reserve Deficiency Accrual - Dec. 38733						
41							-	
42		Net (Salvage)/Cost of Removal					(33,286)	(33,286)
43		Accumulated Depreciation					-	-
44		Accumulated Depreciation - PTYP					(33,286)	(33,286)
45		RUCO Total Accumulated Depreciation - Calculated						
46								(33,286)
47		Company As Filed - Accumulated Depreciation						0
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
			Dec. 58120 1/1/1993 To Present					
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	80
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				53	2,050
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				157	6,066
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				1,302	50,281
23	390	General Plant Structures	2.59%				-	-
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr				186	7,243
25	391	Office Furniture and Equipment	2.59%	94			28	1,088
26	393	Warehouse Equipment	2.59%				1,580	62,009
27	394	Tools, Shop and Garage Equipment	2.59%	2,004			77	2,981
28	395	Laboratory Equipment	2.59%				38	1,458
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		2,097	-	-	3,422	133,256
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						133,256
35								133,256
36		**Company Meter Shop As Filed**						
37								-
38		RUCO Meter Shop Plant Adjustment						
39							-	
40		Reserve Deficiency Accrual - Dec. 38733						
41							-	-
42		Net (Salvage)/Cost of Removal					(36,708)	(36,708)
43		Accumulated Depreciation					-	-
44		Accumulated Depreciation - PTYP					(36,708)	(36,708)
45		RUCO Total Accumulated Depreciation - Calculated						
46								(36,708)
47		Company As Filed - Accumulated Depreciation						0
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
			Dec. 58120 1/1/1993 To Present					
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	2,571			1,336	52,852
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr				-	-
25	391	Office Furniture and Equipment	2.59%	1,610			208	8,853
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	3,115			1,646	65,124
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		7,296	-	-	3,544	140,551
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						140,551
35								
36		**Company Meter Shop As Filed**						140,551
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(40,251)	(40,251)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(40,251)	(40,251)
46								
47		Company As Filed - Accumulated Depreciation						(40,251)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						(0)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								
56		Notes						
57		Acct. 302 - Franchises amortized over 25 years.						
58		Acct. 303 - Other intangibles amortized over 15 & 20 Years.						
59		Acct. 310.4 - Wells - Other amortized over 24 years.						
60		Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.						

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				1,369	52,852
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr				-	-
25	391	Office Furniture and Equipment	2.59%	1,893			254	10,745
26	393	Warehouse Equipment	2.59%	1,089			42	2,177
27	394	Tools, Shop and Garage Equipment	2.59%	2,298			1,716	67,422
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		5,280	-	-	3,707	145,832
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						145,832
35								
36		**Company Meter Shop As Filed**						145,832
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(43,958)	(43,958)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(43,958)	(43,958)
46								
47		Company As Filed - Accumulated Depreciation						(43,959)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						1
49								
50		**RUCO Net Adjustment**						1
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Lakeside System
Schedule WAR-5
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EXPLANATION OF RATE BASE ADJUSTMENT NO. 2
POST TEST-YEAR PLANT - PHOENIX OFFICE

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) COMPANY ADJUSTED TY PLANT	(B) POST TY ADDITIONS	(C) 3-FACTOR ALLOCATOR	(D) REMOVE PTY PLANT
1	301	Organization	$ 40	$ -	6.20%	$ -
2	302	Franchises	-	-	6.20%	-
3	303	Other Intangibles	1,727	-	6.20%	-
4	310.1	Water Rights	220,858	-	6.20%	-
5	310.3	Other Source of Supply Land	14,337	-	6.20%	-
6	310.4	Wells - Other	-	-	6.20%	-
7	314	Wells	1,495,561	-	6.20%	-
8	320	Pumping Plant Land	7,953	-	6.20%	-
9	321	Pumping Plant Structures & Imprm'ts	110,147	-	6.20%	-
10	325	Electtric Pumping Equipment	2,066,419	-	6.20%	-
11	328	Gas Engine Equipment	-	-	6.20%	-
12	330	Water Treatment Plant Land	-	-	6.20%	-
13	331	Water Treatment Structures & Imprm'ts	397	-	6.20%	-
14	332	Water Treatment Equipment	71,947	-	6.20%	-
15	340	Transmission and Distribution Land	23,558	-	6.20%	-
16	342	Storage Tanks	673,012	-	6.20%	-
17	343	Transmission & Distribution Mains	6,911,952	-	6.20%	-
18	344	Fire Sprinkler Taps	79,165	-	6.20%	-
19	345	Services	2,528,006	-	6.20%	-
20	346	Meters	325,314	-	6.20%	-
21	348	Hydrants	610,863	-	6.20%	-
22	389	General Plant Land	1,995	-	6.20%	-
23	390	General Plant Structures	104,383	-	6.20%	-
24	390.1	Leasehold Improvements	136,137	-	6.20%	-
25	391	Office Furniture & Equipment	408,019	120,057	6.20%	7,444
26	393	Warehouse Equipment	3,877	-	6.20%	-
27	394	Tools, Shop & Garage Equipment	72,767	-	6.20%	-
28	395	Laboratory Equipment	638	-	6.20%	-
29	396	Power Operated Equipment	4,909	-	6.20%	-
30	397	Communication Equipment	145,753	-	6.20%	-
31	398	Miscellaneous Equipment	24,885	-	6.20%	-
32		Rounding	1			
33		**TOTAL PTY WATER PLANT**	$ 16,044,619	$ 120,057		$ 7,444
34		Company As Filed	$ 16,044,619	120,057		7,444
35		Difference	$ -	$ -		$ -
36						
37		RUCO PTY Plant Adjustment				$ (7,444)
38						
39		RUCO PTY Accumulated Depreciation Plant Adjustment				$ 248
40						
41						
42		References:				
43		Column (A): Company Schedules B-2				
44		Column (B): Post Test Year Phoenix Office Plant Allocation				
45		Column (C): 3-Factor Allocator				
46		Column (D): Adjustment				

EXPLANATION OF RATE BASE ADJUSTMENT NO. 6
ALLOWANCE FOR WORKING CAPITAL

LINE NO.	DESCRIPTION	(A) AMOUNT	(B) REFERENCE
1	Working Cash Requirement Per Company	$ 23,629	Company Schedule B-5, PG. 1
2	Working Cash Requirement Per RUCO	(48,412)	RUCO Schedule WAR-6, Page 2
3	Adjustment	$ (72,041)	Line 2 - Line 1
4	Material and Supplies Inventories Per Company	$ 445	Company Schedule B-5, PG. 1
5	Material and Supplies Inventories Per RUCO	445	Company Schedule B-5, PG. 1
6	Adjustment	$ -	Line 5 - Line 4
7	Required Bank Balances Per Company	$ 31,894	Company Schedule B-5, PG. 1
8	Required Bank Balances Per RUCO	31,894	Company Schedule B-5, PG. 1
9	Adjustment	$ -	Line 8 - Line 7
10	Prepayments & Special Deposits Per Company	$ 33,298	Company Schedule B-5, PG. 1
11	Prepayments & Special Deposits Per RUCO	33,298	Company Schedule B-5, PG. 1
12	Adjustment	$ -	Line 11 - Line 10
13	TOTAL ADJUSTMENT (See WAR-2, Column (K))	$ (72,041)	Sum of Lines 3, 6, 9 & 12

EXPLANATION OF RATE BASE ADJUSTMENT NO. 6 - CONT'D
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
	Operating Expenses					
1	Purchased Power	$ 181,940	$ -	$ 181,940	35.92	$ 6,535,285
2	Payroll	500,941	(18,770)	482,171	14.00	6,750,392
3	Purchased Water	1,233	-	1,233	(0.11)	(136)
4	Chemicals	7,672	-	7,672	20.43	156,712
5	Property & Liability Insurance	18,521	-	18,521	(45.27)	(838,446)
6	Workman's Compensation Insurance	9,259	-	9,259	(46.50)	(430,544)
7	Health Insurance	154,738	(65)	154,673	(8.92)	(1,379,684)
8	Other Operating & Maintenance Expenses	383,567	(10,333)	373,234	30.00	11,197,020
9	Federal Current Income Taxes	225,485	(77,968)	147,517	37.00	5,458,127
10	State Current Income Taxes	49,672	(17,175)	32,497	37.00	1,202,377
11	FICA Taxes	41,644	(2,984)	38,660	14.00	541,238
12	FUTA & SUTA Taxes	997	-	997	83.10	82,851
13	Property Taxes	116,684	(11,180)	105,504	212.00	22,366,919
14	Registration, Svc. Contracts, & Misc. Fees	35,236	-	35,236	(98.83)	(3,482,374)
15	Retirement Annuities (401k)	51,074	(1,524)	49,550	34.72	1,720,375
16	Subtotal	1,778,663	(139,999)	1,638,664		49,880,113
17	Synchronized Interest	$ 265,900	$ (6,825)	$ 259,075	91.25	$ 23,640,592
18	Cost of Equity	437,706	(437,706)	-	-	-
19	Subtotal	$ 703,606	$ (444,531)	$ 259,075		$ 23,640,592
20	Total	$ 2,482,269	$ (584,530)	$ 1,897,739		$ 73,520,705

21	Expense Lag	Line 17, Col. (E) / (C)	38.74
22	Revenue Lag	Company B-5 Schedules	29.43
23	Net Lag	Line 18 - Line 17	(9.31)
24	RUCO Adjusted Expenses	Col. (C), Line 16	$ 1,897,739
25	Cash Working Capital	Line 19 X Line 20 / 365 Days	(48,412)
26	Company As Filed	Co. Schedule B-6, Page 1	23,629
27	Difference	Line 21 - Line 22	$ (72,041)
28	ADJUSTMENT	Line 27	$ (72,041)

NOTE: Expense Lag Days Used in the Last Western Group Rate Case.
NOTE: Dependent on System
NOTE: RUCO reviewed several invoices from a number of companies with terms of net 30 days.

References:
Column (A): - Company Schedule B-5
Column (B): RUCO Operating Income Adjustments (See Schedule WAR-7)
Column (C): Column (A) + (B)
Column (D): - Company Schedule B-5
Column (E): Column (C) X Column (D)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Lakeside System
Schedule WAR-7
Page 1 of 1

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 2,158,058	$ (28,518)	$ 2,129,540	$ (125,992)	$ 2,003,548
2	Commercial	374,740	(6,399)	368,341	44,815	413,156
3	Industrial	5,354	(112)	5,241	(611)	4,631
4	Private Fire Service	1,557	-	1,557	6,243	7,800
5	Other Water Revenues	23,656	(442)	23,213	5,778	28,992
6	Total Water Revenues	$ 2,563,364	$ (35,472)	$ 2,527,892	$ (69,766)	$ 2,458,126
7	Miscellaneous	$ 25,579	$ -	$ 25,579	$ 214	$ 25,793
8	Total Operating Revenues	$ 2,588,943	$ (35,472)	$ 2,553,472	$ (69,552)	$ 2,483,919
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ 1,233	$ -	$ 1,233	$ -	$ 1,233
10	Other	5,184	-	5,184	-	5,184
11	Pumping Expenses:	-				
12	Purchased Power	181,940	-	181,940	-	181,940
13	Purchased Gas	-	-	-	-	-
14	Other	53,677	-	53,677	-	53,677
15	Water Treatment Expenses	28,463	-	28,463	-	28,463
16	Transmission & Distribution Expenses	290,447	-	290,447	-	290,447
17	Customer Accounting Expenses	275,893	-	275,893	-	275,893
18	Sales Expense	686	-	686	-	686
19	Administrative & General Expenses	506,659	(121,412)	385,247	-	385,247
20	Total Operations & Maintenance Expense	$ 1,344,181	$ (121,412)	$ 1,222,769	$ -	$ 1,222,769
21	Depreciation & Amortization Expenses	$ 416,943	$ (18,874)	$ 398,068	$ -	$ 398,068
	Taxes					
22	Federal Income Taxes	$ 129,724	$ 39,793	$ 169,517	$ (22,000)	$ 147,517
23	State Income Taxes	28,577	8,766	37,343	(4,846)	32,497
24	Property Taxes	116,684	(11,180)	105,504	-	105,504
25	Other	35,117	(2,984)	32,133	-	32,133
26	Total Taxes	$ 310,102	$ 34,395	$ 344,497	$ (26,846)	$ 317,651
27	Total Operating Expenses	$ 2,071,226	$ (105,892)	$ 1,965,334	$ (26,846)	$ 1,938,488
28	Operating Income	$ 517,717	$ 70,420	$ 588,137	$ (42,706)	$ 545,431

References:
Column (A): Company Schedule C-1
Column (B): WAR-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): WAR-1
Column (E): Column (C) + Column (D)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 2,158,058	$ -	$ -	$ -	$ -	$ (28,518)	$ -	$ -	$ -	$ -	$ -	$ 2,129,540
2	Commercial	374,740	-	-	-	-	(6,399)	-	-	-	-	-	368,341
3	Industrial	5,354	-	-	-	-	(112)	-	-	-	-	-	5,241
4	Private Fire Service	1,557	-	-	-	-	-	-	-	-	-	-	1,557
5	Other Water Revenues	23,656	-	-	-	-	(442)	-	-	-	-	-	23,213
6	Total Water Revenues	$ 2,563,364	$ -	$ -	$ -	$ -	$ (35,472)	$ -	$ -	$ -	$ -	$ -	$ 2,527,892
7	Miscellaneous	$ 25,579	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,579
8	Total Operating Revenues	$ 2,588,943	$ -	$ -	$ -	$ -	$ (35,472)	$ -	$ -	$ -	$ -	$ -	$ 2,553,472
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ 1,233	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,233
10	Other	5,184	-	-	-	-	-	-	-	-	-	-	5,184
11	Pumping Expenses:		-	-	-	-	-	-	-	-	-	-	-
12	Purchased Power	181,940	-	-	-	-	-	-	-	-	-	-	181,940
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	53,677	-	-	-	-	-	-	-	-	-	-	53,677
15	Water Treatment Expenses	28,463	-	-	-	-	-	-	-	-	-	-	28,463
16	Transmission & Distribution Expenses	290,447	-	-	-	-	-	-	-	-	-	-	290,447
17	Customer Accounting Expenses	275,893	-	-	-	-	-	-	-	-	-	-	275,893
18	Sales Expense	686	-	-	-	-	-	-	-	-	-	-	686
19	Administrative & General Expenses	506,659	(18,770)	-	(1,524)	(96,920)	-	(65)	-	-	(4,133)	-	385,247
20	Total Operations & Maintenance Expense	$ 1,344,181	$ (18,770)	$ -	$ (1,524)	$ (96,920)	$ -	$ (65)	$ -	$ -	$ (4,133)	$ -	$ 1,222,769
21	Depreciation & Amortization Expenses	$ 416,943	$ -	$ -	$ -	$ -	$ -	$ -	$ (18,874)	$ -	$ -	$ -	$ 398,068
	Taxes												
22	Federal Income Taxes	$ 129,724	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 39,793	$ 169,517
23	State Income Taxes	28,577	-	-	-	-	-	-	-	-	-	8,766	37,343
24	Property Taxes	116,684	-	-	-	-	-	-	-	(11,180)	-	-	105,504
25	Other	35,117	-	(2,984)	-	-	-	-	-	-	-	-	32,133
26	Total Taxes	$ 310,102	$ -	$ (2,984)	$ -	$ -	$ -	$ -	$ -	$ (11,180)	$ -	$ 48,559	$ 344,497
27	Total Operating Expenses	$ 2,071,226	$ (18,770)	$ (2,984)	$ (1,524)	$ (96,920)	$ -	$ (65)	$ (18,874)	$ (11,180)	$ (4,133)	$ 48,559	$ 1,985,334
28	Operating Income	$ 517,717	$ 18,770	$ 2,984	$ 1,524	$ 96,920	$ (35,472)	$ 65	$ 18,874	$ 11,180	$ 4,133	$ (48,559)	$ 568,137

ADJUSTMENTS:
1 - Labor Expense - Normalize OT Hours in Test Year
2 - Payroll Tax Expense Related to Adjustment 1
3 - 401(K) Expense Related to Adjustment 1
4 - Reverse Adjustment for Conservation
5 - Purchased Power Revenues
6 - Insurance Expense
7 - Depreciation Expense
8 - Property Tax Expense
9 - Rate Case Expense
10 - Income Tax

REFERENCE:
Testimony, WAR And Schedule WAR-9 Page, 1 of 3
Testimony, WAR And Schedule WAR-9 Page, 2 of 3
Testimony, WAR And Schedule WAR-9 Page, 3 of 3
Testimony WAR
Testimony WAR
Testimony, WAR And Schedule WAR-10
Testimony, WAR And Schedule WAR-11
Testimony, WAR And Schedule WAR-12
Testimony, WAR And Schedule WAR-13
Testimony, WAR And Schedule WAR-14

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
PAYROLL EXPENSE

LINE NO.	DESCRIPTION		(A) PER RUCO DR 1.11.d
1	Normalize Over-Time Over 4 Years:		
2	2005 OT Hours		15,008.5
3	2006 OT Hours		18,080.0
4	2007 OT Hours		28,132.5
5	2008 OT Hours		17,530.0
6			
7	Total OT Hours for 2005 - 2008		78,751.0
8	Divided by 4 Years		4
9			
10	Normalized Level of OT Hours/Yr.		19,687.8
11			
12	OT Hours in Test Year		28,132.5
13			
14	Amount of Abnormal TY OT Hours		8,444.8
15			
16	Multiplied by Average OT Hrly. Rate	**See NOTE**	35.85
17			
18	Total Abnormal OT Dollars in TY		$ 302,744
19			
20	3-Factor Allocator Per District		6.20%
21			
22	RUCO Adjustment		$ (18,770)
23			
24			
25			
26			
27			
28	3-Factor Allocator By District:		
29	Superstition	24.94%	White Tank 2.37%
30	Bisbee	4.98%	Ajo 0.81%
31	Sierra Vista	2.58%	Coolidge 5.27%
32	San Manuel	1.68%	Lakeside 6.20%
33	Oracle	2.28%	Overgaard 3.99%
34	Winkelman	0.22%	Sedona 8.45%
35	Miami	4.98%	Pinewood 2.95%
36	Casa Grande	26.55%	Rimrock 1.48%
37	Stanfield	0.27%	
38			
39			
40			
41			
42	**Calculation Notes:**		
43	Average of Hourly Rate	$ 21.65	
44	OT Hourly Rate 1.5	32.48	

NOTE: The Company calculated the average hourly rate for overtime in response to data request All-11.6 to be $35.85. RUCO accepts that rate in making its payroll adjustments.

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PAYROLL TAX EXPENSE ASSOCIATED WITH RUCO ADJUSTMENT 1

LINE NO.	DESCRIPTION	(A) PER RUCO DR 1.11.d
1	Payroll Tax Expense:	
2		
3	Total Abnormal OT Dollars in TY	$ 302,744
4		
5	3-Factor Allocator Per District	6.20%
6		
7	RUCO Allocated Payroll by District	$ 18,770
8		
9	Payroll Tax Expense Allocator By Group:	
10		
11	RUCO Payroll Tax Expense Allocator by Group	15.90%
12		
13	RUCO Payroll Tax Expense Adjustment	$ (2,984)
14		
15		
16		
17		
18		
19		
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27		
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29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Payroll Tax Expense Allocator By Group:	
39	Eastern Group 7.47%	
40	Western Group 11.65%	
41	Northern Group 15.90%	

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
PAYROLL 401(K) EXPENSE ASSOCIATED WITH RUCO ADJUSTMENT 1

LINE NO.	DESCRIPTION	(A) PER RUCO DR 1.11.d
1	Payroll 401(K) Expense:	
2		
3	Total Abnormal OT Dollars in TY	$ 302,744
4		
5	3-Factor Allocator Per District	6.20%
6		
7	RUCO Allocated Payroll by District	$ 18,770
8		
9	Payroll 401(K) Expense Allocator By Group:	
10		
11	RUCO Payroll 401(K) Expense Allocator by Group	8.12%
12		
13	RUCO Payroll 401(K) Expense Adjustment	$ (1,524)
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Payroll Tax Expense Allocator By Group:	
39	Eastern Group	8.39%
40	Western Group	8.45%
41	Northern Group	8.12%

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
INSURANCE EXPENSE

LINE NO.		(A) INCREASE/ (DECREASE) LONG-TERM DISABILITY PER COMPANY	(B) RUCO ADJUSTMENT	(C) INCREASE/ (DECREASE) LONG-TERM DISABILITY PER RUCO	
1	System				
2					
3	Eastern Group				
4	Supersition	$ 2,224	$ (273)	$ 1,950	
5	Apache Junction				
6	Superior				
7	Bisbee	122	(45)	77	
8	Sierra Vista	115	(38)	77	
9	San Manuel	5	(20)	(16)	
10	Oracle	25	(20)	5	
11	Saddlebrook	5	(0)	4	
12	Winkelman	0	(2)	(2)	
13	Miami	(338)	(40)	(378)	
14	Subtotal	$ 2,157	$ (439)	$ 1,718	
15					
16	Western Group				
17	Casa Grande	2,137	(298)	1,839	
18	Stanfield	20	(3)	17	
19	White Tank	148	(22)	126	
20	Ajo	58	(9)	49	
21	Coolidge	(127)	(62)	(189)	
22	Subtotal	$ 2,235	$ (393)	$ 1,842	
23					
24	Northern Group				
25	Lakeside	570	(65)	506	
26	Overgaard	507	(55)	452	
27	Sedona	445	(84)	361	
28	Pinewood	199	(38)	162	
29	Rimrock	87	(16)	71	
30	Subtotal	$ 1,809	$ (257)	$ 1,551	
31					
32					
33	Total Company	$ 6,201	$ (1,090)	$ 5,111	(a)

REFERENCE

COLUMN (A): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD
COLUMN (B): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD
COLUMN (C): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD

NOTES:

(a) CALCULATED AS FOLLOWS:		PER COMPANY	RUCO ADJUSTMENT	PER RUCO	REFERENCE
1	Current Rate per Payroll Dollar	$ 0.0036		$ 0.0036	COMPANY WORKPAPER - "GROUP INSURANCE" TAB LTD
2	Pro Forma Payroll Dollars	$ 11,095,569	$ 302,744	$ 10,792,825	COMPANY WORKPAPER - "GROUP INSURANCE)
3	Pro Forma LTD - Total Company	$ 39,944		$ 38,854	LINE 1 x LINE 2
4	Y/E Number of Customers	$ 83,825		$ 83,825	COMPANY WORKPAPER - "GROUP INSURANCE)
5	Pro Forma 2007 LTD - Spread	$ 38,854		$ 38,854	COMPANY WORKPAPER - "GROUP INSURANCE)
6	Increase / (Decrease)	$ 6,201		$ 5,111	COMPANY WORKPAPER - "GROUP INSURANCE)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 7
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCOUNT NO.	ACCOUNT NAME	(A) RUCO PLANT VALUE	(B) COMPANY PROPOSED DEP. RATES	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization	$ 40	0.00%	$ -
2	302	Franchises	-	See Acct. 111	-
3	303	Other Intangibles	1,727	See Acct. 111	-
4	310.1	Water Rights	220,858	0.00%	-
5	310.3	Other Source of Supply Land	14,337	0.00%	-
6	310.4	Wells - Other	-	See Acct. 111	-
7	314	Wells	1,181,737	3.13%	36,988
8	320	Pumping Plant Land	7,953	0.00%	-
9	321	Pumping Plant Structures & Imprm'ts	110,147	2.86%	3,150
10	325	Electtric Pumping Equipment	2,066,419	5.88%	121,505
11	328	Gas Engine Equipment	-	4.00%	-
12	330	Water Treatment Plant Land	-	0.00%	-
13	331	Water Treatment Structures & Imprm'ts	397	2.50%	10
14	332	Water Treatment Equipment	71,947	2.86%	2,058
15	340	Transmission and Distribution Land	23,558	0.00%	-
16	342	Storage Tanks	673,012	2.00%	13,460
17	343	Transmission & Distribution Mains	6,911,952	1.79%	123,724
18	344	Fire Sprinkler Taps	79,165	2.00%	1,583
19	345	Services	2,528,006	2.38%	60,167
20	346	Meters	325,314	4.55%	14,802
21	348	Hydrants	610,863	1.82%	11,118
22	389	General Plant Land	1,995	0.00%	-
23	390	General Plant Structures	104,383	2.50%	2,610
24	390.1	Leasehold Improvements	136,137	See Acct. 108.2	-
25	391	Office Furniture & Equipment	400,575	6.67%	26,718
26	393	Warehouse Equipment	3,877	5.00%	194
27	394	Tools, Shop & Garage Equipment	72,767	4.00%	2,911
28	395	Laboratory Equipment	638	5.00%	32
29	396	Power Operated Equipment	4,909	6.67%	327
30	397	Communication Equipment	145,753	6.67%	9,722
31	398	Miscellaneous Equipment	24,885	3.33%	829
32		Rounding	2		
33		TEST YEAR GROSS PLANT AND DEPRECIATION EXPENSE	$ 15,723,352		$ 431,907
34					
35		AMORTIZATION OF CONTRIBUTIONS	(1,691,940)	2.00%	(33,839)
36		Rounding			-
37	**TOTAL DEPRECIATION EXPENSE**				$ 398,069
38					
39	Company As Filed				416,943
40	Difference				$ (18,874)
41					
42	RUCO Adjustment (See WAR-8, Column (B))				$ (18,874)
43					
44					
45	3-Factor Allocator By District:				
46	Superstition	24.94%	White Tank	2.37%	
47	Bisbee	4.98%	Ajo	0.81%	
48	Sierra Vista	2.58%	Coolidge	5.27%	
49	San Manuel	1.68%	Lakeside	6.20%	
50	Oracle	2.28%	Overgaard	3.99%	
51	Winkelman	0.22%	Sedona	8.45%	
52	Miami	4.98%	Pinewood	2.95%	
53	Casa Grande	26.55%	Rimrock	1.48%	
54	Stanfield	0.27%			

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Lakeside System
Schedule WAR-12

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 8
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A)	(B)
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. WAR-7, Col (C), Ln 8	$ 2,553,472	
2	Adjusted Revenues In Year Ended December 2007	Sch. WAR-7, Col (C), Ln 8	2,553,472	
3	Proposed Revenues	Sch. WAR-7, Col (E), Ln 8	2,483,919	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 7,590,863	
5	Average Annual Operating Revenues	Line 4 / 3	2,530,288	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 5,060,575
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Company Schedule E	$ 92,577	
8	10% Of CWIP	Line 7 X 10%		$ 9,258
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	Company Workpapers	$ -	
10	Acc. Dep. Of Transportation Equipment	Company Workpapers	-	
11	Net Book Value Of Transportation Equipment	Line 9 + Line 10		$ (97,318)
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 4,972,515
	Calculation Of The Company's Tax Liability:			
	MULTIPLY:			
	FCV X Valuation Assessment Ratio X Property Tax Rates:			
13	Assessment Ratio	House Bill 2779	22.5%	
14	Assessed Value	Line 12 X Line 13	$ 1,118,816	
	Property Tax Rates:			
15	Primary Tax Rate	Company Workpapers	9.43%	
16	Secondary Tax Rate	Company Workpapers	0.00%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	9.43%	
	Property Tax			$ 105,504
	Tax On Parcel			-
18	Company's Total Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 105,504
19	Test Year Adjusted Property Tax Expense As Filed	Co. Sch. C-1		116,684
20	Decrease In Property Tax Expense	Line 18 - Line 19		$ (11,180)
21	RUCO Adjustment (See WAR-8, Column (C))	Line 20		$ (11,180)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 9
RATE CASE EXPENSE

LINE NO.	DESCRIPTION	(A) COMPANY ESTIMATE	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total	$ 500,000	$ (200,000)	$ 300,000
2	Allocation Factor			6.20%
3	Lakeside System (Line 1 X Line 2)			$ 18,600
4	Amortization Period - 3 Years			3
5	RUCO Adjusted Rate Case Expense (Line 3 / 3 Years)			$ 6,200
6	Company Rate Case Expenses As Filed (Company Sch. C-2)			$ 10,333
7	RUCO Pro Forma Rate Case Expense (Lines 5 - 6)			$ (4,133)
8	RUCO Adjustment (Line 7) (See WAR-8, Column (E))			$ (4,133)

3-Factor Allocator By District:

Superstition	24.94%	White Tank	2.37%
Bisbee	4.98%	Ajo	0.81%
Sierra Vista	2.58%	Coolidge	5.27%
San Manuel	1.68%	Lakeside	6.20%
Oracle	2.28%	Overgaard	3.99%
Winkelman	0.22%	Sedona	8.45%
Miami	4.98%	Pinewood	2.95%
Casa Grande	26.55%	Rimrock	1.48%
Stanfield	0.27%		

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 10
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. WAR-7, Column (C), L28 + L22 + L23	$ 794,997
	LESS:		
2	Arizona State Tax	Line 11	37,343
3	Interest Expense	Note (A) Line 21	259,075
4	Federal Taxable Income	Line 1 - Line 2 - Line 3	$ 498,579
5	Federal Tax Rate	Sch. WAR-1, Pg 2, Col. (D), L34	34.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 169,517
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 794,997
	LESS:		
8	Interest Expense	Note (A) Line 21	259,075
9	State Taxable Income	Line 7 - Line 8	$ 535,922
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 37,343
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 169,517
13	State Income Tax Expense	Line 11	37,343
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 206,860
15	Total Federal Income Tax Expense Per Company (Per Company Sch. C-1, L30)		129,724
16	Total State Income Tax Expense Per Company (Per Company Sch. C-1, L31)		28,577
17	RUCO Federal Income Tax Adjustment	Line 12 - Line 15	$ 39,793
18	RUCO State Income Tax Adjustment	Line 13 - Line 16	$ 8,766

NOTE (A):
Interest Synchronization:

19	Adjusted Rate Base (Sch. WAR-2, Col. (H), L17)	$ 6,985,207
20	Weighted Cost Of Debt (Sch. WAR-16 Col. (F), L1)	3.71%
21	Interest Expense (L18 X L19)	$ 259,075

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Long-Term Debt	$ 75,000,000	50.76%	7.31%	3.71%
2	Common Equity	72,744,646	49.24%	8.33%	4.10%
3	Total Capitalization	$ 147,744,646	100.00%		
4	WEIGHTED AVERAGE COST OF CAPITAL				7.81%

References:
Columns (A) Thru (D): Testimony, WAR

ARIZONA WATER COMPNAY

W-01445A-08-0440

Overgaard System

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Overgaard System

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WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-4 DIRECT PLANT	1 TO 7	RATE BASE ADJUSTMENT NO. 1 - PLANT & ACCUMULATED DEPRECIATION RECONCILIATION ADJUSTMENT
WAR-4 PHOENIX OFFICE	1 TO 5	RATE BASE ADJUSTMENT NO. 1 - PLANT & ACCUMULATED DEPRECIATION RECONCILIATION ADJUSTMENT
WAR-4 METER SHOP	1 TO 5	RATE BASE ADJUSTMENT NO. 1 - PLANT & ACCUMULATED DEPRECIATION RECONCILIATION ADJUSTMENT
WAR-5	1	RATE BASE ADJUSTMENT NO. 2 - REMOVE POST TEST-YEAR PLANT FOR PHOENIX OFFICE
TESTIMONY		RATE BASE ADJUSTMENT NO. 3 - REMOVE PLANT AND RETIREMENTS INCLUDED IN RATE APPLICATION
		RATE BASE ADJUSTMENT NO. 4 - INTENTIONALLY LEFT BLANK
		RATE BASE ADJUSTMENT NO. 5 - INTENTIONALLY LEFT BLANK
WAR-6	1 & 2	RATE BASE ADJUSTMENT NO. 6 - WORKING CAPITAL AND LEAD/LAG STUDY
WAR-7	1	OPERATING INCOME
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WAR-9	1 OF 3	OPERATING INCOME ADJUSTMENT NO. 1 - PAYROLL EXPENSE
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WAR-10	1	OPERATING INCOME ADJUSTMENT NO. 6 - INSURANCE EXPENSE
WAR-11	1	OPERATING INCOME ADJUSTMENT NO. 7 - TEST YEAR DEPRECIATION EXPENSE
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WAR-14	1	OPERATING INCOME ADJUSTMENT NO. 10 - INCOME TAX EXPENSE
WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 3,338,584	$ 3,252,625
2	Adjusted Operating Income (Loss)	$ 369,890	$ 433,876
3	Current Rate of Return (L2 / L1)	11.08%	13.34%
4	Required Operating Income (L5 X L1)	$ 327,657	$ 253,977
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.81%
6	Operating Income Deficiency (L4 - L2)	$ (42,232)	$ (179,898)
7	Gross Revenue Conversion Factor (WAR-1, Page 2)	1.6286	1.5408
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ (68,781)	$ (277,183)
9	Adjusted Test Year Revenue	$ 1,686,342	$ 1,686,498
10	Proposed Annual Revenue (L8 + L9)	$ 1,617,561	$ 1,409,315
11	Required Percentage Increase in Revenue (L8 / L9)	-4.08%	-16.44%
12	Consolidated Revenue Adjustment (Lakeside/Overgaard)	$ 23,271	$ -
13	Required Increase in Gross Revenue Under Company Proposed Consolidation	$ (45,030)	$ -
14	Required Revenue Under Company Proposed Consolidation	$ 1,640,619	$ -
15	Required Percentage Increase in Revenue Under Company Proposed Consolidation	-2.67%	-
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule WAR-2, WAR-7, and WAR-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3510			
3	Subtotal (L1 - L2)	0.6490			
4	**Revenue Conversion Factor** (L1 / L3)	**1.5408**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	30.2364%			
9	Effective Federal Income Tax Rate (L7 X L8)	28.1295%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	35.0975%			
11	Required Operating Income (Sch. WAR-1, Pg 1, C (B), L4)	$ 253,977			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. WAR-1, Pg 1, C (B), L2)	433,876			
13	Required Increase In Operating Income (L11 - L12)		$ (179,898)		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 72,107			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	169,391			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ (97,284)		
17	Total Required Increase In Revenue (L13 + L16)		$ (277,183)		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. WAR-1, Pg 1, Col. (B), L12)			$ 1,409,315	
19	Operating Expense Excluding Income Tax (WAR-7, Col. (E), L27 - L22 - L23)			1,083,231	
20	Synchronized Interest (Col. (C), L37)			120,637	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 205,447	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 14,316
24	Fed. Taxable Income (L21 - L23)			$ 191,132	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ 6,250	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ 8,500	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ 35,541	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ -	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 57,791
31	Combined Federal and State Income Tax (L23 + L30)				$ 72,107
32	Test Year Combined Income Tax, RUCO as Adjusted (WAR-7, Col. (C), L22 + L23)				$ 169,391
33	RUCO Adjustment (L31 - L32) (See WAR-6, Col. (D), L23)				$ (97,284)
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				30.24%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 3,252,625	
36	Weighted Avg. Cost of Debt (Sch. WAR-16, Col. (F), L1)			3.71%	
37	Synchronized Interest (L35 X L36)			$ 120,637	

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Overgaard System
Schedule WAR-2

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 1,111	$ -	$ 1,111
2	Source of Supply Plant	709,152	-	709,152
3	Pumping Plant	588,420	-	588,420
4	Water Treatment Plant	58,991	-	58,991
5	Transmission & Distribution Plant	8,818,945	-	8,818,945
6	General Plant	728,787	(4,790)	723,997
7	Total Gross Plant in Service	$ 10,905,405	$ (4,790)	$ 10,900,615
8	Accumulated Depreciation	(3,542,894)	789	(3,542,105)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 7,362,511	$ (4,001)	$ 7,358,510
10	Advances In Aid Of Const.	$ (1,420,695)	$ -	$ (1,420,695)
11	Contribution In Aid of Const.	$ (2,543,592)	$ -	$ (2,543,592)
12	Accumulated Amortization of CIAC	613,170	-	613,170
13	NET CIAC (L5 + L6)	$ (1,930,422)	$ -	$ (1,930,422)
14	Deferred Income Tax	$ (764,684)	$ -	$ (764,684)
15	Allowance for Working Capital	$ 91,873	$ (81,957)	$ 9,916
16	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
17	Rounding	$ -	$ -	$ -
18	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 3,338,584	$ (85,959)	$ 3,252,625

References:
Column (A): Company Schedule B-1
Column (B): Schedule WAR-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2 REMOVE PTY PLANT	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 1,111	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,111
2	Source of Supply Plant	709,152	-	-	-	-	-	-	709,152
3	Pumping Plant	588,420	-	-	-	-	-	-	588,420
4	Water Treatment Plant	58,991	-	-	-	-	-	-	58,991
5	Transmission & Distribution Plant	8,818,945	-	-	-	-	-	-	8,818,945
6	General Plant	728,787	-	(4,790)	-	-	-	-	723,997
7	Total Gross Plant in Service	$ 10,905,405	$ -	$ (4,790)	$ -	$ -	$ -	$ -	$ 10,900,615
8	Accumulated Depreciation	$ (3,542,894)	629	160	-	-	-	-	(3,542,105)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 7,362,511	$ 629	$ (4,631)	$ -	$ -	$ -	$ -	$ 7,358,510
10	Advances In Aid Of Const.	$ (1,420,695)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,420,695)
11	Contribution In Aid of Const.	$ (2,543,592)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,543,592)
12	Accumulated Amortization of CIAC	613,170	-	-	-	-	-	-	613,170
13	NET CIAC (L5 + L6)	$ (1,930,422)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,930,422)
14	Deferred Income Tax	$ (764,684)	$ -	$ -	$ -	$ -	$ -	$ -	$ (764,684)
15	Allowance for Working Capital	$ 91,873	$ -	$ -	$ -	$ -	$ -	$ -	$ 91,873
16	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Rounding	$ -							$ -
18	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 3,338,584	$ 629	$ (4,631)	$ -	$ -	$ -	$ -	$ 3,334,582

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See WAR-4 Total, WAR-4 Direct, WAR-4 PHX OFF and WAR-4 MS Schedules and WAR Testimc
Column (C): Adjustment No. 2 - To Remove Post Test Year Phoenix Office Plant and Accum. Depre.
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Intentionally Left Blank
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) Decision 64282 1/1/2002 To Present	(C) 12/31/1999 Per Decision No. 64282	(D) ADJ-1 Remove Post Test Year Plant	(E) Plant Balance 12/31/1999
1	301	Organization	0.00%	0.00%	-	$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111	-	-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111	-	-	-
4	310.1	Water Rights	0.00%	0.00%	44,228	-	44,228
5	310.3	Other Source of Supply Land	0.00%	0.00%	7,086	-	7,086
6	310.4	Wells - Other	See Acct. 111	See Acct. 111	-	-	-
7	314	Wells	2.59%	2.59%	60,886	-	60,886
8	320	Pumping Plant Land	0.00%	0.00%	600	-	600
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	7,969	-	7,969
10	325	Electtric Pumping Equipment	2.59%	2.59%	324,102	-	324,102
11	328	Gas Engine Equipment	2.59%	2.59%	-	-	-
12	330	Water Treatment Plant Land	0.00%	0.00%	-	-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	-	-	-
14	332	Water Treatment Equipment	2.59%	2.59%	49,606	-	49,606
15	340	Transmission and Distribution Land	0.00%	0.00%	29,568	-	29,568
16	342	Storage Tanks	2.59%	2.59%	371,381	-	371,381
17	343	Transmission & Distribution Mains	2.59%	2.59%	3,879,269	-	3,879,269
18	344	Fire Sprinkler Taps	2.59%	2.59%	7,075	-	7,075
19	345	Services	2.59%	2.59%	1,125,892	-	1,125,892
20	346	Meters	2.59%	2.59%	152,761	-	152,761
21	348	Hydrants	2.59%	2.59%	387,747	-	387,747
22	389	General Plant Land	0.00%	0.00%	-	-	-
23	390	General Plant Structures	2.59%	2.59%	201,857	-	201,857
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	-	-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	61,522	-	61,522
26	393	Warehouse Equipment	2.59%	2.59%	-	-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	32,160	-	32,160
28	395	Laboratory Equipment	2.59%	2.59%	390	-	390
29	396	Power Operated Equipment	2.59%	2.59%	731	-	731
30	397	Communication Equipment	2.59%	2.59%	64,779	-	64,779
31	398	Miscellaneous Equipment	2.59%	2.59%	8,252	-	8,252
32		**TOTAL DIRECT WATER PLANT**			$ 6,817,861	$ -	$ 6,817,861
33		Post Test Year Plant (PTYP)			221,664	(221,664)	-
34		**RUCO Total Water Plant In Service**			$ 7,039,525	$ (221,664)	$ 6,817,861
35							
36		**Company Direct Plant As Filed**					
37							
38		**RUCO Direct Plant Adjustment**					
39							
40		Reserve Deficiency Accrual - Decision No. 38733					
41							
42		Net (Salvage)/Cost of Removal					
43		Accumulated Depreciation			(1,788,156)		$ (1,788,156)
44		Accumulated Depreciation - PTYP			(135,967)	135,967.00	-
45		RUCO Total Accumulated Depreciation - Calculated			$ (1,924,123)		$ (1,788,156)
46							
47		Company As Filed - Accumulated Depreciation			-	-	(1,788,156)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ (1,924,123)	$ -	$ -
49							
50		**RUCO Net Adjustment**					
51							
52							
53							

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2000 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2000
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	1,904			-	46,132
5	310.3	Other Source of Supply Land	0.00%	0.00%	8,737			-	15,823
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				1,577	60,886
8	320	Pumping Plant Land	0.00%	0.00%				-	600
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	917			218	8,886
10	325	Electric Pumping Equipment	2.59%	2.59%	41,915	(12,835)		8,771	353,182
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				-	-
14	332	Water Treatment Equipment	2.59%	2.59%	4,239			1,340	53,845
15	340	Transmission and Distribution Land	0.00%	0.00%				-	29,568
16	342	Storage Tanks	2.59%	2.59%	311			9,623	371,892
17	343	Transmission & Distribution Mains	2.59%	2.59%	311,954	(8,862)		104,398	4,182,361
18	344	Fire Sprinkler Taps	2.59%	2.59%	2,675			218	9,750
19	345	Services	2.59%	2.59%	60,138	(1,989)		29,914	1,184,041
20	346	Meters	2.59%	2.59%	17,163	(2,464)		4,147	167,460
21	348	Hydrants	2.59%	2.59%	51,782			10,713	439,529
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				5,228	201,857
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	75			1,594	61,597
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	5,072			899	37,232
28	395	Laboratory Equipment	2.59%	2.59%				10	390
29	396	Power Operated Equipment	2.59%	2.59%	126			21	857
30	397	Communication Equipment	2.59%	2.59%	1,820			1,701	66,599
31	398	Miscellaneous Equipment	2.59%	2.59%	235			217	8,487
32		**TOTAL DIRECT WATER PLANT**			$ 509,061	$ (26,150)	$ -	$ 180,588	$ 7,300,772
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 509,061	$ (26,150)	$ -	$ 180,588	$ 7,300,772
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(26)	
41									
42		Net (Salvage)/Cost of Removal						-	
43		Accumulated Depreciation						(1,942,620)	$ (1,942,620)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(1,942,620)	$ (1,942,620)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(1,943,066)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (1,942,620)	$ 446
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2001 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2001
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	1,779			-	47,911
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	15,823
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	509,550			8,176	570,436
8	320	Pumping Plant Land	0.00%	0.00%				-	600
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	21,572	(3,645)		462	26,813
10	325	Electtric Pumping Equipment	2.59%	2.59%	95,822	(1,589)		10,368	447,414
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	166			2	166
14	332	Water Treatment Equipment	2.59%	2.59%	2,510	(2,840)		1,390	53,515
15	340	Transmission and Distribution Land	0.00%	0.00%				-	29,568
16	342	Storage Tanks	2.59%	2.59%	1,016			9,640	372,708
17	343	Transmission & Distribution Mains	2.59%	2.59%	415,423	(29,891)		113,316	4,567,893
18	344	Fire Sprinkler Taps	2.59%	2.59%				253	9,750
19	345	Services	2.59%	2.59%	129,659	(10,321)		32,212	1,303,378
20	346	Meters	2.59%	2.59%	14,965	(681)		4,522	181,744
21	348	Hydrants	2.59%	2.59%	48,230			12,008	487,759
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	2,379			5,259	204,236
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	245			1,599	61,841
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	181			967	37,413
28	395	Laboratory Equipment	2.59%	2.59%				10	390
29	396	Power Operated Equipment	2.59%	2.59%	1,066	(152)		34	1,771
30	397	Communication Equipment	2.59%	2.59%	9,878			1,853	76,477
31	398	Miscellaneous Equipment	2.59%	2.59%	1,103			234	9,590
32		**TOTAL DIRECT WATER PLANT**			$ 1,255,543	$ (49,119)	$ -	$ 202,304	$ 8,507,196
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 1,255,543	$ (49,119)	$ -	$ 202,304	$ 8,507,196
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(26)	
41									
42		Net (Salvage)/Cost of Removal						(354)	
43		Accumulated Depreciation						(2,096,185)	$ (2,096,185)
44		Accumulated Depreciation - PTYP						-	$ -
45		RUCO Total Accumulated Depreciation - Calculated						(2,096,185)	$ (2,096,185)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,096,788)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,096,185)	$ 603
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2002 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2002
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	9,964			-	57,875
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	15,823
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				14,774	570,436
8	320	Pumping Plant Land	0.00%	0.00%				-	600
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	6,733			782	33,546
10	325	Electtric Pumping Equipment	2.59%	2.59%	32,175	(10,487)		11,869	469,103
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				4	166
14	332	Water Treatment Equipment	2.59%	2.59%				1,386	53,515
15	340	Transmission and Distribution Land	0.00%	0.00%				-	29,568
16	342	Storage Tanks	2.59%	2.59%	2,033			9,679	374,741
17	343	Transmission & Distribution Mains	2.59%	2.59%	261,175	(1,517)		121,671	4,827,550
18	344	Fire Sprinkler Taps	2.59%	2.59%	5,914			329	15,664
19	345	Services	2.59%	2.59%	68,728	(751)		34,638	1,371,355
20	346	Meters	2.59%	2.59%	12,097	(1,409)		4,846	192,433
21	348	Hydrants	2.59%	2.59%	55,792			13,355	543,551
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	4,137			5,343	208,373
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	719			1,611	62,561
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	1,278			986	38,691
28	395	Laboratory Equipment	2.59%	2.59%				10	390
29	396	Power Operated Equipment	2.59%	2.59%				46	1,771
30	397	Communication Equipment	2.59%	2.59%	7,036			2,072	83,513
31	398	Miscellaneous Equipment	2.59%	2.59%				248	9,590
32		**TOTAL DIRECT WATER PLANT**			$ 467,783	$ (14,164)	$ -	$ 223,650	$ 8,960,815
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 467,783	$ (14,164)	$ -	$ 223,650	$ 8,960,815
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(26)	
41									
42		Net (Salvage)/Cost of Removal						(152)	
43		Accumulated Depreciation						(2,305,848)	$ (2,305,848)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(2,305,848)	(2,305,848)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,306,538)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,305,848)	$ 690
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2003 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2003
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	7,117			-	64,992
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	15,823
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				14,774	570,436
8	320	Pumping Plant Land	0.00%	0.00%				-	600
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	155			871	33,701
10	325	Electric Pumping Equipment	2.59%	2.59%	12,068	(12,209)		12,148	468,961
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				4	166
14	332	Water Treatment Equipment	2.59%	2.59%				1,386	53,515
15	340	Transmission and Distribution Land	0.00%	0.00%				-	29,568
16	342	Storage Tanks	2.59%	2.59%				9,706	374,741
17	343	Transmission & Distribution Mains	2.59%	2.59%	348,093	(12,261)		129,383	5,163,382
18	344	Fire Sprinkler Taps	2.59%	2.59%	12,324			565	27,988
19	345	Services	2.59%	2.59%	67,378	(4,349)		36,334	1,434,384
20	346	Meters	2.59%	2.59%	4,651	(1,706)		5,022	195,377
21	348	Hydrants	2.59%	2.59%	15,194			14,275	558,745
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	2,087			5,424	210,460
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	1,124			1,635	63,685
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	1,464			1,021	40,155
28	395	Laboratory Equipment	2.59%	2.59%				10	390
29	396	Power Operated Equipment	2.59%	2.59%				46	1,771
30	397	Communication Equipment	2.59%	2.59%	5,152			2,230	88,665
31	398	Miscellaneous Equipment	2.59%	2.59%	758			258	10,348
32		**TOTAL DIRECT WATER PLANT**			$ 477,564	$ (30,525)	$ -	$ 235,092	$ 9,407,854
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 477,564	$ (30,525)	$ -	$ 235,092	$ 9,407,854
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(26)	
41									
42		Net (Salvage)/Cost of Removal						(2,273)	
43		Accumulated Depreciation						(2,512,714)	$ (2,512,714)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(2,512,714)	(2,512,714)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,513,403)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,512,714)	$ 689
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111	746			-	746
4	310.1	Water Rights	0.00%	0.00%	3,929			-	68,921
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	15,823
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	502			14,781	570,938
8	320	Pumping Plant Land	0.00%	0.00%				-	600
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	582			880	34,282
10	325	Electtric Pumping Equipment	2.59%	2.59%	41,148			12,679	510,109
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				4	166
14	332	Water Treatment Equipment	2.59%	2.59%	1,592			1,407	55,107
15	340	Transmission and Distribution Land	0.00%	0.00%				-	29,568
16	342	Storage Tanks	2.59%	2.59%				9,706	374,741
17	343	Transmission & Distribution Mains	2.59%	2.59%	57,341			134,474	5,220,723
18	344	Fire Sprinkler Taps	2.59%	2.59%				725	27,988
19	345	Services	2.59%	2.59%	39,911			37,667	1,474,295
20	346	Meters	2.59%	2.59%	4,581	(1,619)		5,099	198,339
21	348	Hydrants	2.59%	2.59%	26,425			14,814	585,170
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	2,069			5,478	212,529
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	10,531			1,786	74,216
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	522			1,047	40,677
28	395	Laboratory Equipment	2.59%	2.59%				10	390
29	396	Power Operated Equipment	2.59%	2.59%	1,708			68	3,480
30	397	Communication Equipment	2.59%	2.59%	3,715	(1,990)		2,319	90,391
31	398	Miscellaneous Equipment	2.59%	2.59%	1,387			286	11,734
32		**TOTAL DIRECT WATER PLANT**			$ 196,687	$ (3,609)	$ -	$ 243,229	$ 9,600,932
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 196,687	$ (3,609)	$ -	$ 243,229	$ 9,600,932
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(26)	
41									
42		Net (Salvage)/Cost of Removal						(42)	
43		Accumulated Depreciation						(2,752,402)	$ (2,752,402)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(2,752,402)	(2,752,402)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,753,091)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,752,402)	$ 689
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	746
4	310.1	Water Rights	0.00%	0.00%	8,035			-	76,956
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	15,823
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	691			14,796	571,629
8	320	Pumping Plant Land	0.00%	0.00%				-	600
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	612			896	34,894
10	325	Electtric Pumping Equipment	2.59%	2.59%	9,715			13,338	519,824
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				4	166
14	332	Water Treatment Equipment	2.59%	2.59%	862			1,438	55,968
15	340	Transmission and Distribution Land	0.00%	0.00%				-	29,568
16	342	Storage Tanks	2.59%	2.59%				9,706	374,741
17	343	Transmission & Distribution Mains	2.59%	2.59%	114,487			136,699	5,335,209
18	344	Fire Sprinkler Taps	2.59%	2.59%	10,273			858	38,261
19	345	Services	2.59%	2.59%	64,329			39,017	1,538,623
20	346	Meters	2.59%	2.59%	11,076	(946)		5,268	208,469
21	348	Hydrants	2.59%	2.59%	36,352			15,627	621,522
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	7,021			5,595	219,550
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	5,311			1,991	79,527
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	2,991			1,092	43,669
28	395	Laboratory Equipment	2.59%	2.59%				10	390
29	396	Power Operated Equipment	2.59%	2.59%	272			94	3,752
30	397	Communication Equipment	2.59%	2.59%	1,606			2,362	91,997
31	398	Miscellaneous Equipment	2.59%	2.59%	163			306	11,897
32		**TOTAL DIRECT WATER PLANT**			$ 273,795	$ (946)	$ -	$ 249,098	$ 9,873,781
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 273,795	$ (946)	$ -	$ 249,098	$ 9,873,781
35									
36		**Company Direct Plant As Filed**							-
37									
38		**RUCO Direct Plant Adjustment**							$ 9,873,781
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(26)	
41									
42		Net (Salvage)/Cost of Removal						-	
43		Accumulated Depreciation						(3,000,580)	$ (3,000,580)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(3,000,580)	(3,000,580)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(3,001,269)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (3,000,580)	$ 689
49									
50		**RUCO Net Adjustment**							$ 9,874,471
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	746
4	310.1	Water Rights	0.00%	0.00%	9,764			-	86,720
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	15,823
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				14,805	571,629
8	320	Pumping Plant Land	0.00%	0.00%				-	600
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	359			908	35,253
10	325	Electtric Pumping Equipment	2.59%	2.59%	37,792	(16,527)		13,739	541,089
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				4	166
14	332	Water Treatment Equipment	2.59%	2.59%	1,390			1,468	57,358
15	340	Transmission and Distribution Land	0.00%	0.00%				-	29,568
16	342	Storage Tanks	2.59%	2.59%				9,706	374,741
17	343	Transmission & Distribution Mains	2.59%	2.59%	95,015			139,412	5,430,224
18	344	Fire Sprinkler Taps	2.59%	2.59%				991	38,261
19	345	Services	2.59%	2.59%	76,675	(2,037)		40,817	1,613,262
20	346	Meters	2.59%	2.59%	9,421	(761)		5,512	217,129
21	348	Hydrants	2.59%	2.59%	4,091			16,150	625,613
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				5,686	219,550
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	1,115			2,074	80,642
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	1,743			1,154	45,412
28	395	Laboratory Equipment	2.59%	2.59%				10	390
29	396	Power Operated Equipment	2.59%	2.59%				97	3,752
30	397	Communication Equipment	2.59%	2.59%	7,195			2,476	99,192
31	398	Miscellaneous Equipment	2.59%	2.59%	155			310	12,052
32		**TOTAL DIRECT WATER PLANT**			$ 244,716	$ (19,325)	$ -	$ 255,320	$ 10,099,172
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 244,716	$ (19,325)	$ -	$ 255,320	$ 10,099,172
35									
36		**Company Direct Plant As Filed**							-
37									
38		**RUCO Direct Plant Adjustment**							$ 10,099,172
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						(140)	
43		Accumulated Depreciation						(3,236,714)	$ (3,236,714)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(3,236,714)	(3,236,714)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(3,237,404)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (3,236,714)	$ 690
49									
50		**RUCO Net Adjustment**							$ 10,099,862
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				37	746
4	310.1	Water Rights	0.00%	0.00%	29,525			-	116,245
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	15,823
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	5,452			14,876	577,081
8	320	Pumping Plant Land	0.00%	0.00%				-	600
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	934			925	36,187
10	325	Electtric Pumping Equipment	2.59%	2.59%	10,545			14,151	551,634
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				4	166
14	332	Water Treatment Equipment	2.59%	2.59%	1,385			1,504	58,743
15	340	Transmission and Distribution Land	0.00%	0.00%				-	29,568
16	342	Storage Tanks	2.59%	2.59%	290,472			13,467	665,214
17	343	Transmission & Distribution Mains	2.59%	2.59%	108,246			142,045	5,538,471
18	344	Fire Sprinkler Taps	2.59%	2.59%				991	38,261
19	345	Services	2.59%	2.59%	77,752			42,790	1,691,013
20	346	Meters	2.59%	2.59%	9,904	(1,431)		5,733	225,602
21	348	Hydrants	2.59%	2.59%	4,958			16,268	630,571
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	1,993			5,712	221,543
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	3,592			2,135	84,234
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	3,615			1,223	49,027
28	395	Laboratory Equipment	2.59%	2.59%				10	390
29	396	Power Operated Equipment	2.59%	2.59%				97	3,752
30	397	Communication Equipment	2.59%	2.59%	9,407	(1,300)		2,674	107,299
31	398	Miscellaneous Equipment	2.59%	2.59%				312	12,052
32		**TOTAL DIRECT WATER PLANT**			$ 557,781	$ (2,731)	$ -	$ 264,955	$ 10,654,222
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 557,781	$ (2,731)	$ -	$ 264,955	$ 10,654,222
35									
36		**Company Direct Plant As Filed**							10,654,222
37									
38		**RUCO Direct Plant Adjustment**							$ (0)
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						-	
43		Accumulated Depreciation						(3,498,938)	$ (3,498,938)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(3,498,938)	(3,498,938)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(3,499,629)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (3,498,938)	$ 691
49									
50		**RUCO Net Adjustment**							$ 691
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2003 12/31/2003 Per Decision 68302	2003 ADJ-1 Remove Post Test Year Plant	2003 Balance 12/31/2003
1	301	Organization	0.00%	651		651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.	8,496		8,496
4	310.1	Water Rights	0.00%	-		-
5	310.3	Other Source of Supply Land	0.00%	-		-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
7	314	Wells	2.59%	-		-
8	320	Pumping Plant Land	0.00%	-		-
9	321	Pumping Plant Structures and Improvements	2.59%	-		-
10	325	Electric Pumping Equipment	2.59%	-		-
11	328	Gas Engine Equipment	2.59%	-		-
12	330	Water Treatment Plant Land	0.00%	-		-
13	331	Water Treatment Structures and Improvements	2.59%	-		-
14	332	Water Treatment Equipment	2.59%	-		-
15	340	Transmission and Distribution Land	0.00%	-		-
16	342	Storage Tanks	2.59%	-		-
17	343	Transmission and Distribution Mains	2.59%	-		-
18	344	Fire Sprinkler Taps	2.59%	-		-
19	345	Services	2.59%	-		-
20	346	Meters	2.59%	-		-
21	348	Hydrants	2.59%	-		-
22	389	General Plant Land	0.00%	-		-
23	390	General Plant Structures	2.59%	31,795		31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	1,267,373		1,267,373
25	391	Office Furniture and Equipment	2.59%	3,505,411		3,505,411
26	393	Warehouse Equipment	2.59%	3,705		3,705
27	394	Tools, Shop and Garage Equipment	2.59%	30,450		30,450
28	395	Laboratory Equipment	2.59%	977		977
29	396	Power Operated Equipment	2.59%	-		-
30	397	Communication Equipment	2.59%	143,052		143,052
31	398	Miscellaneous Equipment	2.59%	7,207		7,207
32		**TOTAL PHOENIX OFFICE PLANT**		4,999,117	-	4,999,117
33		Post Test Year Plant (PTYP)		-	-	-
34		**RUCO Total Phoenix Office**		4,999,117	-	4,999,117
35						
36		**Company Phoenix Office As Filed**		4,999,117		4,999,117
37						
38		RUCO Phoenix Office Plant Adjustment		-		-
39						
40		Reserve Deficiency Accrual - Dec. 38733		-		-
41						
42		Net (Salvage)/Cost of Removal				
43		Accumulated Depreciation		(503,775)	-	(503,775)
44		Accumulated Depreciation - PTYP		-	-	-
45		RUCO Total Accumulated Depreciation - Calculated		(503,775)	-	(503,775)
46						
47		Company As Filed - Accumulated Depreciation				(503,775)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**				-
49						
50		**RUCO Net Adjustment**				
51						
52						
53						
54						
55						

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
			Dec. 58120					
			1/1/1993					
			To Present					
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	48,512			78,228	1,315,885
25	391	Office Furniture and Equipment	2.59%	129,135	(7,465)		92,366	3,627,081
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	24,820			1,110	55,270
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	6,465			3,789	149,517
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		208,932	(7,465)	-	176,624	5,200,584
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,200,584
35								
36		**Company Phoenix Office As Filed**						5,200,584
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(672,934)	(672,934)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(672,934)	(672,934)
46								
47		Company As Filed - Accumulated Depreciation						(672,934)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(0)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				89,580	1,315,885
25	391	Office Furniture and Equipment	2.59%	221,339			96,808	3,848,420
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	20,585			1,698	75,855
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	885			3,884	150,402
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		242,809	-	-	193,101	5,443,393
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,443,393
35								
36		**Company Phoenix Office As Filed**						5,443,393
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(866,035)	(866,035)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(866,035)	(866,035)
46								
47		Company As Filed - Accumulated Depreciation						(866,035)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
			Dec. 58120 1/1/1993 To Present					
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				94,864	1,315,885
25	391	Office Furniture and Equipment	2.59%	369,071			104,454	4,217,491
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	59,519			2,735	135,374
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	1,741			3,918	152,143
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		430,332	-	-	207,102	5,873,725
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,873,725
35								
36		**Company Phoenix Office As Filed**						5,873,725
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(1,073,138)	(1,073,138)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(1,073,138)	(1,073,138)
46								
47		Company As Filed - Accumulated Depreciation						(1,073,137)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(1)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
			Dec. 58120					
			1/1/1993					
			To Present					
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				425	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	10,463			959	42,258
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	93			86,708	1,315,978
25	391	Office Furniture and Equipment	2.59%	464,535	(243,714)		112,093	4,438,312
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	40,312			4,028	175,686
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	4,089			3,993	156,232
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		519,493	(243,714)	-	208,514	6,149,503
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						6,149,503
35								
36		**Company Phoenix Office As Filed**						6,149,503
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(1,037,938)	(1,037,938)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(1,037,938)	(1,037,938)
46								
47		Company As Filed - Accumulated Depreciation						(1,036,382)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(1,556)
49								
50		**RUCO Net Adjustment**						(1,556)
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2003 12/31/2003 Per Decision 68302	2003 ADJ-1 Remove Post Test Year Plant	2003 Balance 12/31/2003
1	301	Organization	0.00%	-		-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
4	310.1	Water Rights	0.00%	-		-
5	310.3	Other Source of Supply Land	0.00%	80		80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
7	314	Wells	2.59%	-		-
8	320	Pumping Plant Land	0.00%	-		-
9	321	Pumping Plant Structures and Improvements	2.59%	-		-
10	325	Electric Pumping Equipment	2.59%	-		-
11	328	Gas Engine Equipment	2.59%	-		-
12	330	Water Treatment Plant Land	0.00%	-		-
13	331	Water Treatment Structures and Improvements	2.59%	-		-
14	332	Water Treatment Equipment	2.59%	2,050		2,050
15	340	Transmission and Distribution Land	0.00%	-		-
16	342	Storage Tanks	2.59%	-		-
17	343	Transmission and Distribution Mains	2.59%	6,066		6,066
18	344	Fire Sprinkler Taps	2.59%	-		-
19	345	Services	2.59%	-		-
20	346	Meters	2.59%	-		-
21	348	Hydrants	2.59%	-		-
22	389	General Plant Land	0.00%	-		-
23	390	General Plant Structures	2.59%	37,472		37,472
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	-		-
25	391	Office Furniture and Equipment	2.59%	3,983		3,983
26	393	Warehouse Equipment	2.59%	1,088		1,088
27	394	Tools, Shop and Garage Equipment	2.59%	58,430		58,430
28	395	Laboratory Equipment	2.59%	2,981		2,981
29	396	Power Operated Equipment	2.59%	1,458		1,458
30	397	Communication Equipment	2.59%	-		-
31	398	Miscellaneous Equipment	2.59%	-		-
32		**TOTAL METER SHOP PLANT**		113,608	-	113,608
33		Post Test Year Plant (PTYP)		-	-	-
34		**RUCO Total Meter Shop**		113,608	-	113,608
35						
36		**Company Meter Shop As Filed**		113,608		113,608
37						
38		RUCO Meter Shop Plant Adjustment		-		-
39						
40		Reserve Deficiency Accrual - Dec. 38733				
41						
42		Net (Salvage)/Cost of Removal				
43		Accumulated Depreciation		(30,118)	-	(30,118)
44		Accumulated Depreciation - PTYP		-	-	-
45		RUCO Total Accumulated Depreciation - Calculated		(30,118)	-	(30,118)
46						
47		Company As Filed - Accumulated Depreciation				(30,118)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**				-
49						
50		**RUCO Net Adjustment**				
51						
52						
53						
54						
55						
56		Notes				
57		Acct. 302 - Franchises amortized over 25 years.				
58		Acct. 303 - Other intangibles amortized over 15 & 20 Years.				
59		Acct. 310.4 - Wells - Other amortized over 24 years.				
60		Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.				

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	12,809			1,136	50,281
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr				-	-
25	391	Office Furniture and Equipment	2.59%	3,166			144	7,149
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	1,575			1,534	60,005
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		17,550	-	-	3,168	131,158
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						131,158
35								
36		**Company Meter Shop As Filed**						131,158
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733						
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(33,286)	(33,286)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(33,286)	(33,286)
46								
47		Company As Filed - Accumulated Depreciation						(33,286)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				1,302	50,281
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr				-	-
25	391	Office Furniture and Equipment	2.59%	94			186	7,243
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	2,004			1,580	62,009
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		2,097	-	-	3,422	133,256
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						133,256
35								
36		**Company Meter Shop As Filed**						133,256
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(36,708)	(36,708)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(36,708)	(36,708)
46								
47		Company As Filed - Accumulated Depreciation						(36,708)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
			Dec. 58120 1/1/1993 To Present					
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	2,571			1,336	52,852
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr				-	-
25	391	Office Furniture and Equipment	2.59%	1,610			208	8,853
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	3,115			1,646	65,124
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		7,296	-	-	3,544	140,551
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						140,551
35								
36		**Company Meter Shop As Filed**						140,551
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(40,251)	(40,251)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(40,251)	(40,251)
46								
47		Company As Filed - Accumulated Depreciation						(40,251)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						(0)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				1,369	52,852
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr				-	-
25	391	Office Furniture and Equipment	2.59%	1,893			254	10,745
26	393	Warehouse Equipment	2.59%	1,089			42	2,177
27	394	Tools, Shop and Garage Equipment	2.59%	2,298			1,716	67,422
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		5,280	-	-	3,707	145,832
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						145,832
35								
36		**Company Meter Shop As Filed**						145,832
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(43,958)	(43,958)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(43,958)	(43,958)
46								
47		Company As Filed - Accumulated Depreciation						(43,959)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						1
49								
50		**RUCO Net Adjustment**						1
51								
52								
53								
54								
55								
56		Notes						
57		Acct. 302 - Franchises amortized over 25 years.						
58		Acct. 303 - Other intangibles amortized over 15 & 20 Years.						
59		Acct. 310.4 - Wells - Other amortized over 24 years.						
60		Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.						

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EXPLANATION OF RATE BASE ADJUSTMENT NO. 2
POST TEST-YEAR PLANT - PHOENIX OFFICE

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) COMPANY ADJUSTED TY PLANT	(B) POST TY ADDITIONS	(C) 3-FACTOR ALLOCATOR	(D) REMOVE PTY PLANT
1	301	Organization	$ 26	$ -	3.99%	$ -
2	302	Franchises	-	-	3.99%	-
3	303	Other Intangibles	1,085	-	3.99%	-
4	310.1	Water Rights	116,245	-	3.99%	-
5	310.3	Other Source of Supply Land	15,826	-	3.99%	-
6	310.4	Wells - Other	-	-	3.99%	-
7	314	Wells	577,081	-	3.99%	-
8	320	Pumping Plant Land	600	-	3.99%	-
9	321	Pumping Plant Structures & Imprm'ts	36,187	-	3.99%	-
10	325	Electtric Pumping Equipment	551,634	-	3.99%	-
11	328	Gas Engine Equipment	-	-	3.99%	-
12	330	Water Treatment Plant Land	-	-	3.99%	-
13	331	Water Treatment Structures & Imprm'ts	166	-	3.99%	-
14	332	Water Treatment Equipment	58,825	-	3.99%	-
15	340	Transmission and Distribution Land	29,568	-	3.99%	-
16	342	Storage Tanks	665,214	-	3.99%	-
17	343	Transmission & Distribution Mains	5,538,713	-	3.99%	-
18	344	Fire Sprinkler Taps	38,261	-	3.99%	-
19	345	Services	1,691,013	-	3.99%	-
20	346	Meters	225,602	-	3.99%	-
21	348	Hydrants	630,571	-	3.99%	-
22	389	General Plant Land	-	-	3.99%	-
23	390	General Plant Structures	225,338	-	3.99%	-
24	390.1	Leasehold Improvements	52,508	-	3.99%	-
25	391	Office Furniture & Equipment	261,752	120,057	3.99%	4,790
26	393	Warehouse Equipment	235	-	3.99%	-
27	394	Tools, Shop & Garage Equipment	58,727	-	3.99%	-
28	395	Laboratory Equipment	548	-	3.99%	-
29	396	Power Operated Equipment	3,810	-	3.99%	-
30	397	Communication Equipment	113,533	-	3.99%	-
31	398	Miscellaneous Equipment	12,340	-	3.99%	-
32		Rounding	(1)			
33		**TOTAL PTY WATER PLANT**	$ 10,905,405	$ 120,057		$ 4,790
34		Company As Filed	$ 10,905,405	120,057		4,790
35		Difference	$ -	$ -		$ -
36						
37		RUCO PTY Plant Adjustment				$ (4,790)
38						
39		RUCO PTY Accumulated Depreciation Plant Adjustment				$ 160
40						
41						
42		References:				
43		Column (A): Company Schedules B-2				
44		Column (B): Post Test Year Phoenix Office Plant Allocation				
45		Column (C): 3-Factor Allocator				
46		Column (D): Adjustment				

EXPLANATION OF RATE BASE ADJUSTMENT NO. 6
ALLOWANCE FOR WORKING CAPITAL

LINE NO.	DESCRIPTION	(A) AMOUNT	(B) REFERENCE
1	Working Cash Requirement Per Company	$ 48,580	Company Schedule B-5, PG. 1
2	Working Cash Requirement Per RUCO	(33,377)	RUCO Schedule WAR-6, Page 2
3	Adjustment	$ (81,957)	Line 2 - Line 1
4	Material and Supplies Inventories Per Company	$ 1,339	Company Schedule B-5, PG. 1
5	Material and Supplies Inventories Per RUCO	1,339	Company Schedule B-5, PG. 1
6	Adjustment	$ -	Line 5 - Line 4
7	Required Bank Balances Per Company	$ 20,525	Company Schedule B-5, PG. 1
8	Required Bank Balances Per RUCO	20,525	Company Schedule B-5, PG. 1
9	Adjustment	$ -	Line 8 - Line 7
10	Prepayments & Special Deposits Per Company	$ 21,429	Company Schedule B-5, PG. 1
11	Prepayments & Special Deposits Per RUCO	21,429	Company Schedule B-5, PG. 1
12	Adjustment	$ -	Line 11 - Line 10
13	TOTAL ADJUSTMENT (See WAR-2, Column (K))	$ (81,957)	Sum of Lines 3, 6, 9 & 12

EXPLANATION OF RATE BASE ADJUSTMENT NO. 6 - CONT'D
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
	Operating Expenses					
1	Purchased Power	$ 71,171	$ -	$ 71,171	35.92	$ 2,556,462
2	Payroll	22,262	(12,079)	10,183	14.00	142,555
3	Purchased Water	58	-	58	(0.11)	(6)
4	Chemicals	6,009	-	6,009	20.43	122,743
5	Property & Liability Insurance	11,919	-	11,919	(45.27)	(539,573)
6	Workman's Compensation Insurance	5,959	-	5,959	(46.50)	(277,094)
7	Health Insurance	69,507	(55)	69,452	(8.92)	(619,513)
8	Other Operating & Maintenance Expenses	626,570	(6,650)	619,920	30.00	18,597,585
9	Federal Current Income Taxes	105,005	(47,214)	57,791	37.00	2,138,281
10	State Current Income Taxes	23,132	(8,816)	14,316	37.00	529,676
11	FICA Taxes	26,800	(1,920)	24,880	14.00	348,314
12	FUTA & SUTA Taxes	641	-	641	83.10	53,267
13	Property Taxes	65,159	(5,068)	60,091	212.00	12,739,199
14	Registration, Svc. Contracts, & Misc. Fees	22,676	-	22,676	(98.83)	(2,241,069)
15	Retirement Annuities (401k)	22,942	(981)	21,961	34.72	762,476
16	Subtotal	1,079,809	(82,784)	997,025		34,313,303
17	Synchronized Interest	$ 123,825	$ (3,188)	$ 120,637	91.25	$ 11,008,118
18	Cost of Equity	203,832	(203,832)	-	-	-
19	Subtotal	$ 327,657	$ (207,020)	$ 120,637		$ 11,008,118
20	Total	$ 1,407,466	$ (289,804)	$ 1,117,662		$ 45,321,422

21	Expense Lag	Line 17, Col. (E) / (C)	40.55
22	Revenue Lag	Company B-5 Schedules	29.65
23	Net Lag	Line 18 - Line 17	(10.90)
24	RUCO Adjusted Expenses	Col. (C), Line 16	$ 1,117,662
25	Cash Working Capital	Line 19 X Line 20 / 365 Days	(33,377)
26	Company As Filed	Co. Schedule B-6, Page 1	48,580
27	Difference	Line 21 - Line 22	$ (81,957)
28	ADJUSTMENT	Line 27	$ (81,957)

NOTE: Expense Lag Days Used in the Last Western Group Rate Case.
NOTE: Dependent on System
NOTE: RUCO reviewed several invoices from a number of companies with terms of net 30 days.

References:
Column (A): - Company Schedule B-5
Column (B): RUCO Operating Income Adjustments (See Schedule WAR-7)
Column (C): Column (A) + (B)
Column (D): - Company Schedule B-5
Column (E): Column (C) X Column (D)

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OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 1,521,187	$ 137	$ 1,521,324	$ (276,030)	$ 1,245,294
2	Commercial	129,575	16	129,591	(7,045)	122,546
3	Industrial	-	-	-	-	-
4	Private Fire Service	1,195	-	1,195	4,805	6,000
5	Other Water Revenues	9,963	2	9,965	875	10,840
6	Total Water Revenues	$ 1,661,920	$ 156	$ 1,662,076	$ (277,396)	$ 1,384,680
7	Miscellaneous	$ 24,422	$ -	$ 24,422	$ 213	$ 24,635
8	Total Operating Revenues	$ 1,686,342	$ 156	$ 1,686,498	$ (277,183)	$ 1,409,315
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ 58	$ -	$ 58	$ -	$ 58
10	Other	4,378	-	4,378	-	4,378
11	Pumping Expenses:	-				
12	Purchased Power	71,171	-	71,171	-	71,171
13	Purchased Gas	-	-	-	-	-
14	Other	43,941	-	43,941	-	43,941
15	Water Treatment Expenses	14,733	-	14,733	-	14,733
16	Transmission & Distribution Expenses	237,473	-	237,473	-	237,473
17	Customer Accounting Expenses	207,198	-	207,198	-	207,198
18	Sales Expense	446	-	446	-	446
19	Administrative & General Expenses	279,673	(67,752)	211,922	-	211,922
20	Total Operations & Maintenance Expense	$ 859,072	$ (67,752)	$ 791,321	$ -	$ 791,321
21	Depreciation & Amortization Expenses	$ 214,780	$ (3,796)	$ 210,984	$ -	$ 210,984
	Taxes					
22	Federal Income Taxes	$ 126,761	$ 9,001	$ 135,762	$ (77,970)	$ 57,791
23	State Income Taxes	27,924	5,705	33,630	(19,314)	14,316
24	Property Taxes	65,159	(5,068)	60,091	-	60,091
25	Other	22,756	(1,920)	20,836	-	20,836
26	Total Taxes	$ 242,600	$ 7,717	$ 250,317	$ (97,284)	$ 153,033
27	Total Operating Expenses	$ 1,316,453	$ (63,830)	$ 1,252,622	$ (97,284)	$ 1,155,338
28	Operating Income	$ 369,890	$ 63,986	$ 433,876	$ (179,899)	$ 253,977

References:
Column (A): Company Schedule C-1
Column (B): WAR-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): WAR-1
Column (E): Column (C) + Column (D)

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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 1,521,187	$ -	$ -	$ -	$ -	$ 137	$ -	$ -	$ -	$ -	$ -	$ 1,521,324
2	Commercial	129,575	-	-	-	-	16	-	-	-	-	-	129,591
3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-
4	Private Fire Service	1,195	-	-	-	-	-	-	-	-	-	-	1,195
5	Other Water Revenues	9,963	-	-	-	-	2	-	-	-	-	-	9,965
6	Total Water Revenues	$ 1,661,920	$ -	$ -	$ -	$ -	$ 156	$ -	$ -	$ -	$ -	$ -	$ 1,662,076
7	Miscellaneous	$ 24,422	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,422
8	Total Operating Revenues	$ 1,686,342	$ -	$ -	$ -	$ -	$ 156	$ -	$ -	$ -	$ -	$ -	$ 1,686,498
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ 58	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 58
10	Other	4,378	-	-	-	-	-	-	-	-	-	-	4,378
11	Pumping Expenses:		-	-	-	-	-	-	-	-	-	-	-
12	Purchased Power	71,171	-	-	-	-	-	-	-	-	-	-	71,171
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	43,941	-	-	-	-	-	-	-	-	-	-	43,941
15	Water Treatment Expenses	14,733	-	-	-	-	-	-	-	-	-	-	14,733
16	Transmission & Distribution Expenses	237,473	-	-	-	-	-	-	-	-	-	-	237,473
17	Customer Accounting Expenses	207,198	-	-	-	-	-	-	-	-	-	-	207,198
18	Sales Expense	446	-	-	-	-	-	-	-	-	-	-	446
19	Administrative & General Expenses	279,673	(12,079)	-	(981)	(51,977)	-	(55)	-	-	(2,660)	-	211,922
20	Total Operations & Maintenance Expense	$ 859,072	$ (12,079)	$ -	$ (981)	$ (51,977)	$ -	$ (55)	$ -	$ -	$ (2,660)	$ -	$ 791,321
21	Depreciation & Amortization Expenses	$ 214,780	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,796)	$ -	$ -	$ -	$ 210,984
	Taxes												
22	Federal Income Taxes	$ 126,761	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,001	$ 135,762
23	State Income Taxes	27,924	-	-	-	-	-	-	-	-	-	5,705	33,630
24	Property Taxes	65,159	-	-	-	-	-	-	-	(5,068)	-	-	60,091
25	Other	22,756	-	(1,920)	-	-	-	-	-	-	-	-	20,836
26	Total Taxes	$ 242,600	$ -	$ (1,920)	$ -	$ -	$ -	$ -	$ -	$ (5,068)	$ -	$ 14,706	$ 250,317
27	Total Operating Expenses	$ 1,316,453	$ (12,079)	$ (1,920)	$ (981)	$ (51,977)	$ -	$ (55)	$ (3,796)	$ (5,068)	$ (2,660)	$ 14,706	$ 1,252,622
28	Operating Income	$ 369,890	$ 12,079	$ 1,920	$ 981	$ 51,977	$ 156	$ 55	$ 3,796	$ 5,068	$ 2,660	$ (14,706)	$ 433,876

ADJUSTMENTS:
1 - Labor Expense - Normalize OT Hours in Test Year
2 - Payroll Tax Expense Related to Adjustment 1
3 - 401(K) Expense Related to Adjustment 1
4 - Reverse Adjustment for Conservation
5 - Purchased Power Revenues
6 - Insurance Expense
7 - Depreciation Expense
8 - Property Tax Expense
9 - Rate Case Expense
10 - Income Tax

REFERENCE:
Testimony, WAR And Schedule WAR-9 Page, 1 of 3
Testimony, WAR And Schedule WAR-9 Page, 2 of 3
Testimony, WAR And Schedule WAR-9 Page, 3 of 3
Testimony WAR
Testimony WAR
Testimony, WAR And Schedule WAR-10
Testimony, WAR And Schedule WAR-11
Testimony, WAR And Schedule WAR-12
Testimony, WAR And Schedule WAR-13
Testimony, WAR And Schedule WAR-14

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
PAYROLL EXPENSE

LINE NO.	DESCRIPTION		(A) PER RUCO DR 1.11.d
1	Normalize Over-Time Over 4 Years:		
2	2005 OT Hours		15,008.5
3	2006 OT Hours		18,080.0
4	2007 OT Hours		28,132.5
5	2008 OT Hours		17,530.0
6			
7	Total OT Hours for 2005 - 2008		78,751.0
8	Divided by 4 Years		4
9			
10	Normalized Level of OT Hours/Yr.		19,687.8
11			
12	OT Hours in Test Year		28,132.5
13			
14	Amount of Abnormal TY OT Hours		8,444.8
15			
16	Multiplied by Average OT Hrly. Rate	**See NOTE**	35.85
17			
18	Total Abnormal OT Dollars in TY		$ 302,744
19			
20	3-Factor Allocator Per District		3.99%
21			
22	RUCO Adjustment		$ (12,079)
23			
24			
25			
26			
27			
28	3-Factor Allocator By District:		
29	Superstition	24.94%	White Tank 2.37%
30	Bisbee	4.98%	Ajo 0.81%
31	Sierra Vista	2.58%	Coolidge 5.27%
32	San Manuel	1.68%	Lakeside 6.20%
33	Oracle	2.28%	Overgaard 3.99%
34	Winkelman	0.22%	Sedona 8.45%
35	Miami	4.98%	Pinewood 2.95%
36	Casa Grande	26.55%	Rimrock 1.48%
37	Stanfield	0.27%	
38			
39			
40			
41			
42	**Calculation Notes:**		
43	Average of Hourly Rate	$ 21.65	
44	OT Hourly Rate 1.5	32.48	

NOTE: The Company calculated the average hourly rate for overtime in response to data request AII-11.6 to be $35.85. RUCO accepts that rate in making its payroll adjustments.

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PAYROLL TAX EXPENSE ASSOCIATED WITH RUCO ADJUSTMENT 1

LINE NO.	DESCRIPTION	(A) PER RUCO DR 1.11.d
1	Payroll Tax Expense:	
2		
3	Total Abnormal OT Dollars in TY	$ 302,744
4		
5	3-Factor Allocator Per District	3.99%
6		
7	RUCO Allocated Payroll by District	$ 12,079
8		
9	Payroll Tax Expense Allocator By Group:	
10		
11	RUCO Payroll Tax Expense Allocator by Group	15.90%
12		
13	RUCO Payroll Tax Expense Adjustment	$ (1,920)
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Payroll Tax Expense Allocator By Group:	
39	Eastern Group	7.47%
40	Western Group	11.65%
41	Northern Group	15.90%

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
PAYROLL 401(K) EXPENSE ASSOCIATED WITH RUCO ADJUSTMENT 1

LINE NO.	DESCRIPTION	(A) PER RUCO DR 1.11.d
1	Payroll 401(K) Expense:	
2		
3	Total Abnormal OT Dollars in TY	$ 302,744
4		
5	3-Factor Allocator Per District	3.99%
6		
7	RUCO Allocated Payroll by District	$ 12,079
8		
9	Payroll 401(K) Expense Allocator By Group:	
10		
11	RUCO Payroll 401(K) Expense Allocator by Group	8.12%
12		
13	RUCO Payroll 401(K) Expense Adjustment	$ (981)
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Payroll Tax Expense Allocator By Group:	
39	Eastern Group 8.39%	
40	Western Group 8.45%	
41	Northern Group 8.12%	

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
INSURANCE EXPENSE

LINE NO.		(A) INCREASE/ (DECREASE) LONG-TERM DISABILITY PER COMPANY	(B) RUCO ADJUSTMENT	(C) INCREASE/ (DECREASE) LONG-TERM DISABILITY PER RUCO
1	System			
2				
3	Eastern Group			
4	Supersition	$ 2,224	$ (273)	$ 1,950
5	Apache Junction			
6	Superior			
7	Bisbee	122	(45)	77
8	Sierra Vista	115	(38)	77
9	San Manuel	5	(20)	(16)
10	Oracle	25	(20)	5
11	Saddlebrook	5	(0)	4
12	Winkelman	0	(2)	(2)
13	Miami	(338)	(40)	(378)
14	Subtotal	$ 2,157	$ (439)	$ 1,718
15				
16	Western Group			
17	Casa Grande	2,137	(298)	1,839
18	Stanfield	20	(3)	17
19	White Tank	148	(22)	126
20	Ajo	58	(9)	49
21	Coolidge	(127)	(62)	(189)
22	Subtotal	$ 2,235	$ (393)	$ 1,842
23				
24	Northern Group			
25	Lakeside	570	(65)	506
26	Overgaard	507	(55)	452
27	Sedona	445	(84)	361
28	Pinewood	199	(38)	162
29	Rimrock	87	(16)	71
30	Subtotal	$ 1,809	$ (257)	$ 1,551
31				
32				
33	Total Company	$ 6,201	$ (1,090)	$ 5,111 (a)

REFERENCE

COLUMN (A): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD
COLUMN (B): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD
COLUMN (C): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD

NOTES:

(a) CALCULATED AS FOLLOWS:		PER COMPANY	RUCO ADJUSTMENT	PER RUCO	REFERENCE
1	Current Rate per Payroll Dollar	$ 0.0036		$ 0.0036	COMPANY WORKPAPER - "GROUP INSURANCE" TAB LTD
2	Pro Forma Payroll Dollars	$ 11,095,569	$ 302,744	$ 10,792,825	COMPANY WORKPAPER - "GROUP INSURANCE)
3	Pro Forma LTD - Total Company	$ 39,944		$ 38,854	LINE 1 x LINE 2
4	Y/E Number of Customers	$ 83,825		$ 83,825	COMPANY WORKPAPER - "GROUP INSURANCE)
5	Pro Forma 2007 LTD - Spread	$ 38,854		$ 38,854	COMPANY WORKPAPER - "GROUP INSURANCE)
6	Increase / (Decrease)	$ 6,201		$ 5,111	COMPANY WORKPAPER - "GROUP INSURANCE)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 7
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCOUNT NO.	ACCOUNT NAME	(A) RUCO PLANT VALUE	(B) COMPANY PROPOSED DEP. RATES	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization	$ 26	0.00%	$ -
2	302	Franchises	-	See Acct. 111	-
3	303	Other Intangibles	1,085	See Acct. 111	37
4	310.1	Water Rights	116,245	0.00%	-
5	310.3	Other Source of Supply Land	15,826	0.00%	-
6	310.4	Wells - Other	-	See Acct. 111	-
7	314	Wells	577,081	3.13%	18,063
8	320	Pumping Plant Land	600	0.00%	-
9	321	Pumping Plant Structures & Imprm'ts	36,187	2.86%	1,035
10	325	Electtric Pumping Equipment	551,634	5.88%	32,436
11	328	Gas Engine Equipment	-	4.00%	-
12	330	Water Treatment Plant Land	-	0.00%	-
13	331	Water Treatment Structures & Imprm'ts	166	2.50%	4
14	332	Water Treatment Equipment	58,825	2.86%	1,682
15	340	Transmission and Distribution Land	29,568	0.00%	-
16	342	Storage Tanks	665,214	2.00%	13,304
17	343	Transmission & Distribution Mains	5,538,713	1.79%	99,143
18	344	Fire Sprinkler Taps	38,261	2.00%	765
19	345	Services	1,691,013	2.38%	40,246
20	346	Meters	225,602	4.55%	10,265
21	348	Hydrants	630,571	1.82%	11,476
22	389	General Plant Land	-	0.00%	-
23	390	General Plant Structures	225,338	2.50%	5,633
24	390.1	Leasehold Improvements	52,508	See Acct. 108.2	-
25	391	Office Furniture & Equipment	256,962	6.67%	17,139
26	393	Warehouse Equipment	235	5.00%	12
27	394	Tools, Shop & Garage Equipment	58,727	4.00%	2,349
28	395	Laboratory Equipment	548	5.00%	27
29	396	Power Operated Equipment	3,810	6.67%	254
30	397	Communication Equipment	113,533	6.67%	7,573
31	398	Miscellaneous Equipment	12,340	3.33%	411
32		Rounding	(1)		
33		TEST YEAR GROSS PLANT AND DEPRECIATION EXPENSE	$ 10,900,615		$ 261,856
34					
35		AMORTIZATION OF CONTRIBUTIONS	(2,543,592)	2.00%	(50,872)
36		Rounding			-
37	**TOTAL DEPRECIATION EXPENSE**				$ 210,984
38					
39	Company As Filed				214,780
40	Difference				$ (3,796)
41					
42	RUCO Adjustment (See WAR-8, Column (B))				$ (3,796)
43					
44					
45	3-Factor Allocator By District:				
46	Superstition	24.94%	White Tank	2.37%	
47	Bisbee	4.98%	Ajo	0.81%	
48	Sierra Vista	2.58%	Coolidge	5.27%	
49	San Manuel	1.68%	Lakeside	6.20%	
50	Oracle	2.28%	Overgaard	3.99%	
51	Winkelman	0.22%	Sedona	8.45%	
52	Miami	4.98%	Pinewood	2.95%	
	Casa Grande	26.55%	Rimrock	1.48%	
	Stanfield	0.27%			

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 8
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A)	(B)
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. WAR-7, Col (C), Ln 8	$ 1,686,498	
2	Adjusted Revenues In Year Ended December 2007	Sch. WAR-7, Col (C), Ln 8	1,686,498	
3	Proposed Revenues	Sch. WAR-7, Col (E), Ln 8	1,409,315	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 4,782,311	
5	Average Annual Operating Revenues	Line 4 / 3	1,594,104	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 3,188,207
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Company Schedule E	$ 3,725	
8	10% Of CWIP	Line 7 X 10%		$ 373
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	Company Workpapers	$ -	
10	Acc. Dep. Of Transportation Equipment	Company Workpapers	-	
11	Net Book Value Of Transportation Equipment	Line 9 + Line 10		$ (53,965)
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 3,134,615
	Calculation Of The Company's Tax Liability:			
	MULTIPLY:			
	FCV X Valuation Assessment Ratio X Property Tax Rates:			
13	Assessment Ratio	House Bill 2779	22.5%	
14	Assessed Value	Line 12 X Line 13	$ 705,288	
	Property Tax Rates:			
15	Primary Tax Rate	Company Workpapers	8.52%	
16	Secondary Tax Rate	Company Workpapers	0.00%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	8.52%	
	Property Tax			$ 60,091
	Tax On Parcel			-
18	Company's Total Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 60,091
19	Test Year Adjusted Property Tax Expense As Filed	Co. Sch. C-1		65,159
20	Decrease In Property Tax Expense	Line 18 - Line 19		$ (5,068)
21	RUCO Adjustment (See WAR-8, Column (C))	Line 20		$ (5,068)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 9
RATE CASE EXPENSE

LINE NO.	DESCRIPTION	(A) COMPANY ESTIMATE	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total	$ 500,000	$ (200,000)	$ 300,000
2	Allocation Factor			3.99%
3	Overgaard System (Line 1 X Line 2)			$ 11,970
4	Amortization Period - 3 Years			3
5	RUCO Adjusted Rate Case Expense (Line 3 / 3 Years)			$ 3,990
6	Company Rate Case Expenses As Filed (Company Sch. C-2)			$ 6,650
7	RUCO Pro Forma Rate Case Expense (Lines 5 - 6)			$ (2,660)
8	RUCO Adjustment (Line 7) (See WAR-8, Column (E))			$ (2,660)

3-Factor Allocator By District:

Superstition	24.94%	White Tank	2.37%
Bisbee	4.98%	Ajo	0.81%
Sierra Vista	2.58%	Coolidge	5.27%
San Manuel	1.68%	Lakeside	6.20%
Oracle	2.28%	Overgaard	3.99%
Winkelman	0.22%	Sedona	8.45%
Miami	4.98%	Pinewood	2.95%
Casa Grande	26.55%	Rimrock	1.48%
Stanfield	0.27%		

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 10
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. WAR-7, Column (C), L28 + L22 + L23	$ 603,267
	LESS:		
2	Arizona State Tax	Line 11	33,630
3	Interest Expense	Note (A) Line 21	120,637
4	Federal Taxable Income	Line 1 - Line 2 - Line 3	$ 449,000
5	Federal Tax Rate	Sch. WAR-1, Pg 2, Col. (D), L34	30.24%
6	Federal Income Tax Expense	Line 4 X line 5	$ 135,762
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 603,267
	LESS:		
8	Interest Expense	Note (A) Line 21	120,637
9	State Taxable Income	Line 7 - Line 8	$ 482,630
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 33,630
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 135,762
13	State Income Tax Expense	Line 11	33,630
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 169,391
15	Total Federal Income Tax Expense Per Company (Per Company Sch. C-1, L30)		126,761
16	Total State Income Tax Expense Per Company (Per Company Sch. C-1, L31)		27,924
17	RUCO Federal Income Tax Adjustment	Line 12 - Line 15	$ 9,001
18	RUCO State Income Tax Adjustment	Line 13 - Line 16	$ 5,705

NOTE (A):
Interest Synchronization:

19	Adjusted Rate Base (Sch. WAR-2, Col. (H), L17)	$ 3,252,625
20	Weighted Cost Of Debt (Sch. WAR-16 Col. (F), L1)	3.71%
21	Interest Expense (L18 X L19)	$ 120,637

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Long-Term Debt	$ 75,000,000	50.76%	7.31%	3.71%
2	Common Equity	72,744,646	49.24%	8.33%	4.10%
3	Total Capitalization	$ 147,744,646	100.00%		
4	WEIGHTED AVERAGE COST OF CAPITAL				7.81%

References:
Columns (A) Thru (D): Testimony, WAR

ARIZONA WATER COMPNAY

W-01445A-08-0440

Sedona System

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Sedona System

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WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-4 DIRECT PLANT	1 TO 7	RATE BASE ADJUSTMENT NO. 1 - PLANT & ACCUMULATED DEPRECIATION RECONCILIATION ADJUSTMENT
WAR-4 PHOENIX OFFICE	1 TO 5	RATE BASE ADJUSTMENT NO. 1 - PLANT & ACCUMULATED DEPRECIATION RECONCILIATION ADJUSTMENT
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WAR-7	1	OPERATING INCOME
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WAR-9	1 OF 3	OPERATING INCOME ADJUSTMENT NO. 1 - PAYROLL EXPENSE
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WAR-14	1	OPERATING INCOME ADJUSTMENT NO. 10 - INCOME TAX EXPENSE
WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 18,018,530	$ 14,673,180
2	Adjusted Operating Income (Loss)	$ 424,708	$ 546,742
3	Current Rate of Return (L2 / L1)	2.36%	3.73%
4	Required Operating Income (L5 X L1)	$ 1,768,386	$ 1,145,738
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.81%
6	Operating Income Deficiency (L4 - L2)	$ 1,343,679	$ 598,995
7	Gross Revenue Conversion Factor (WAR-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 2,188,362	$ 975,545
9	Adjusted Test Year Revenue	$ 3,521,124	$ 3,518,537
10	Proposed Annual Revenue (L8 + L9)	$ 5,709,486	$ 4,494,082
11	Required Percentage Increase in Revenue (L8 / L9)	62.15%	27.73%
12	Consolidated Revenue Adjustment (Sedona/Pinewood/Rimrock)	$ 216,885	$ -
13	Required Increase in Gross Revenue Under Company Proposed Consolidation	$ 2,404,707	$ -
14	Required Revenue Under Company Proposed Consolidation	$ 5,926,065	$ -
15	Required Percentage Increase in Revenue Under Company Proposed Consolidation	68.29%	-
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule WAR-2, WAR-7, and WAR-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. WAR-1, Pg 1, C (B), L4)	$ 1,145,738			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. WAR-1, Pg 1, C (B), L2)	546,742			
13	Required Increase In Operating Income (L11 - L12)		$ 598,995		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 378,138			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	1,589			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 376,549		
17	Total Required Increase In Revenue (L13 + L16)		$ 975,545		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. WAR-1, Pg 1, Col. (B), L12)			$ 4,494,082	
19	Operating Expense Excluding Income Tax (WAR-7, Col. (E), L27 - L22 - L23)			2,970,206	
20	Synchronized Interest (Col. (C), L37)			544,215	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 979,661	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 68,263
24	Fed. Taxable Income (L21 - L23)			$ 911,398	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ 6,250	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ 8,500	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ 91,650	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 195,975	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 309,875
31	Combined Federal and State Income Tax (L23 + L30)				$ 378,138
32	Test Year Combined Income Tax, RUCO as Adjusted (WAR-7, Col. (C), L22 + L23)				$ 1,589
33	RUCO Adjustment (L31 - L32) (See WAR-6, Col. (D), L23)				$ 376,549
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 14,673,180	
36	Weighted Avg. Cost of Debt (Sch. WAR-16, Col. (F), L1)			3.71%	
37	Synchronized Interest (L35 X L36)			$ 544,215	

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 3,287	$ -	$ 3,287
2	Source of Supply Plant	5,917,390	(3,397,718)	2,519,672
3	Pumping Plant	2,266,429	(6,761)	2,259,668
4	Water Treatment Plant	1,297,124	-	1,297,124
5	Transmission & Distribution Plant	23,674,185	(661,738)	23,012,447
6	General Plant	1,166,200	(10,145)	1,156,055
7	Total Gross Plant in Service	$ 34,324,616	$ (4,076,362)	$ 30,248,254
8	Accumulated Depreciation	(6,146,140)	949,332	(5,196,809)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 28,178,476	$ (3,127,030)	$ 25,051,445
10	Advances In Aid Of Const.	$ (3,651,412)	$ -	$ (3,651,412)
11	Contribution In Aid of Const.	$ (6,396,542)	$ -	$ (6,396,542)
12	Accumulated Amortization of CIAC	1,279,254	-	1,279,254
13	NET CIAC (L5 + L6)	$ (5,117,288)	$ -	$ (5,117,288)
14	Deferred Income Tax	$ (1,619,443)	$ -	$ (1,619,443)
15	Allowance for Working Capital	228,197	$ (218,320)	$ 9,878
16	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
17	Rounding	$ -	$ -	$ -
18	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 18,018,530	$ (3,345,350)	$ 14,673,180

References:
Column (A): Company Schedule B-1
Column (B): Schedule WAR-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Sedona System
Schedule WAR-3
Page 1 of 1

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2 REMOVE P.O. PTY PLANT	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4 REMOVE PTY PLANT 11.16	(F) ADJMT NO. 5 REMOVE PTY PLANT	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 3,287	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,287
2	Source of Supply Plant	5,917,390	-	-	(1,386,142)	(2,011,576)	-	-	2,519,672
3	Pumping Plant	2,266,429	-	-	(6,761)	-	-	-	2,259,668
4	Water Treatment Plant	1,297,124	-	-	-	-	-	-	1,297,124
5	Transmission & Distribution Plant	23,674,185	-	-	-	-	(661,738)	-	23,012,447
6	General Plant	1,166,200	-	(10,145)	-	-	-	-	1,156,055
7	Total Gross Plant in Service	$ 34,324,616	$ -	$ (10,145)	$ (1,392,903)	$ (2,011,576)	$ (661,738)	$ -	$ 30,248,254
8	Accumulated Depreciation	(6,146,140)	(4,975)	338	926,106	21,940	5,923	-	(5,196,809)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 28,178,476	$ (4,975)	$ (9,806)	$ (466,797)	$ (1,989,636)	$ (655,815)	$ -	$ 25,051,445
10	Advances In Aid Of Const.	$ (3,651,412)	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,651,412)
11	Contribution In Aid of Const.	$ (6,396,542)	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,396,542)
12	Accumulated Amortization of CIAC	1,279,254	-	-	-	-	-	-	1,279,254
13	NET CIAC (L5 + L6)	$ (5,117,288)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,117,288)
14	Deferred Income Tax	$ (1,619,443)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,619,443)
15	Allowance for Working Capital	228,197	$ -	$ -	$ -	$ -	$ -	$ (218,320)	$ 9,878
16	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Rounding	$ -							$ -
18	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 18,018,530	$ (4,975)	$ (9,806)	$ (466,797)	$ (1,989,636)	$ (655,815)	$ (218,320)	$ 14,673,180

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See WAR-4 Total, WAR-4 Direct, WAR-4 PHX OFF and WAR-4 MS Schedules and WAR Testim
Column (C): Adjustment No. 2 - To Remove Post Test Year Phoenix Office Plant and Accum. Depre.
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - To Remove Post Test Year Plant Included in Rate Application
Column (F): Adjustment No. 5 - Intentionally Left Blank
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	(C) 12/31/1999 Per Decision No. 64282	(D) ADJ-1 Remove Post Test Year Plant	(E) Plant Balance 12/31/1999
1	301	Organization	0.00%	0.00%	-	$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111	935	-	935
3	303	Other Intangibles	See Acct. 111	See Acct. 111	-	-	-
4	310.1	Water Rights	0.00%	0.00%	9,063	-	9,063
5	310.3	Other Source of Supply Land	0.00%	0.00%	49,986	-	49,986
6	310.4	Wells - Other	See Acct. 111	See Acct. 111	-	-	-
7	314	Wells	2.59%	2.59%	1,807,751	-	1,807,751
8	320	Pumping Plant Land	0.00%	0.00%	3,805	-	3,805
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	49,436	-	49,436
10	325	Electtric Pumping Equipment	2.59%	2.59%	1,160,127	-	1,160,127
11	328	Gas Engine Equipment	2.59%	2.59%	223	-	223
12	330	Water Treatment Plant Land	0.00%	0.00%	-	-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	32,114	-	32,114
14	332	Water Treatment Equipment	2.59%	2.59%	164,474	-	164,474
15	340	Transmission and Distribution Land	0.00%	0.00%	112,947	-	112,947
16	342	Storage Tanks	2.59%	2.59%	1,008,531	-	1,008,531
17	343	Transmission & Distribution Mains	2.59%	2.59%	8,549,776	-	8,549,776
18	344	Fire Sprinkler Taps	2.59%	2.59%	340,109	-	340,109
19	345	Services	2.59%	2.59%	1,538,263	-	1,538,263
20	346	Meters	2.59%	2.59%	382,634	-	382,634
21	348	Hydrants	2.59%	2.59%	655,795	-	655,795
22	389	General Plant Land	0.00%	0.00%	-	-	-
23	390	General Plant Structures	2.59%	2.59%	34,037	-	34,037
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	47,178	-	47,178
25	391	Office Furniture & Equipment	2.59%	2.59%	105,560	-	105,560
26	393	Warehouse Equipment	2.59%	2.59%	6,711	-	6,711
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	55,853	-	55,853
28	395	Laboratory Equipment	2.59%	2.59%	2,485	-	2,485
29	396	Power Operated Equipment	2.59%	2.59%	9,305	-	9,305
30	397	Communication Equipment	2.59%	2.59%	86,569	-	86,569
31	398	Miscellaneous Equipment	2.59%	2.59%	10,427	-	10,427
32		TOTAL DIRECT WATER PLANT			$ 16,224,094	$ -	$ 16,224,094
33		Post Test Year Plant (PTYP)			855,744	(855,744)	-
34		**RUCO Total Water Plant In Service**			$ 17,079,838	$ (855,744)	$ 16,224,094
35							
36		**Company Direct Plant As Filed**					
37							
38		**RUCO Direct Plant Adjustment**					
39							
40		Reserve Deficiency Accrual - Decision No. 38733					
41							
42		Net (Salvage)/Cost of Removal					
43		Accumulated Depreciation			(3,488,743)		$ (3,488,743)
44		Accumulated Depreciation - PTYP			(363,307)	363,307	-
45		RUCO Total Accumulated Depreciation - Calculated			$ (3,852,050)		$ (3,488,743)
46							
47		Company As Filed - Accumulated Depreciation			-	-	(3,488,743)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ (3,852,050)	$ -	$ -
49							
50		**RUCO Net Adjustment**					
51							
52							
53							
54		References:					
55		Column (A): Approved Depreciation Rate From Decision No. 58120					
56		Columns (B): Approved Depreciation Rate From Decision No. 66849					
57		Acct. 302 - Franchises amortized over 25 years.					
58		Acct. 303 - Other Intangibles amortized over 15 & 20 Years.					
59		Acct. 310.4 - Wells - Other amortized over 24 years.					
60		Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.					

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2000 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2000
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	935
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	1,565			-	10,628
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	49,986
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	342,440	(447)		51,250	2,149,743
8	320	Pumping Plant Land	0.00%	0.00%				-	3,805
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	22			1,281	49,458
10	325	Electtric Pumping Equipment	2.59%	2.59%	115,462	(17,477)		31,316	1,258,112
11	328	Gas Engine Equipment	2.59%	2.59%				6	223
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				832	32,114
14	332	Water Treatment Equipment	2.59%	2.59%	85,153	(19,000)		5,117	230,627
15	340	Transmission and Distribution Land	0.00%	0.00%				-	112,947
16	342	Storage Tanks	2.59%	2.59%	12,045			26,277	1,020,576
17	343	Transmission & Distribution Mains	2.59%	2.59%	570,644	(5,790)		228,754	9,114,630
18	344	Fire Sprinkler Taps	2.59%	2.59%	80,191	(516)		9,841	419,784
19	345	Services	2.59%	2.59%	113,703	(5,059)		41,248	1,646,907
20	346	Meters	2.59%	2.59%	25,309	(2,595)		10,204	405,348
21	348	Hydrants	2.59%	2.59%	76,293			17,973	732,088
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	825	(175)		890	34,687
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				9,036	47,178
25	391	Office Furniture & Equipment	2.59%	2.59%	509			2,741	106,069
26	393	Warehouse Equipment	2.59%	2.59%				174	6,711
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	3,238			1,489	59,091
28	395	Laboratory Equipment	2.59%	2.59%				64	2,485
29	396	Power Operated Equipment	2.59%	2.59%	3,044			280	12,349
30	397	Communication Equipment	2.59%	2.59%	5,671			2,316	92,240
31	398	Miscellaneous Equipment	2.59%	2.59%	1,393			288	11,820
32		**TOTAL DIRECT WATER PLANT**			$ 1,437,505	$ (51,059)	$ -	$ 441,375	$ 17,610,540
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 1,437,505	$ (51,059)	$ -	$ 441,375	$ 17,610,540
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(68)	
41									
42		Net (Salvage)/Cost of Removal						93	
43		Accumulated Depreciation						(3,879,034)	$ (3,879,034)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(3,879,034)	$ (3,879,034)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(3,879,538)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (3,879,034)	$ 504
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2001 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2001
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	935
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	390			-	11,018
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	49,986
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	(224,752)			52,768	1,924,991
8	320	Pumping Plant Land	0.00%	0.00%				-	3,805
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	17,964			1,514	67,422
10	325	Electtric Pumping Equipment	2.59%	2.59%	46,580	(7,986)		33,085	1,296,706
11	328	Gas Engine Equipment	2.59%	2.59%				6	223
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	23,630			1,138	55,744
14	332	Water Treatment Equipment	2.59%	2.59%	38,652	(59,759)		5,700	209,520
15	340	Transmission and Distribution Land	0.00%	0.00%				-	112,947
16	342	Storage Tanks	2.59%	2.59%	12,125			26,590	1,032,701
17	343	Transmission & Distribution Mains	2.59%	2.59%	334,528	(10,362)	(787)	240,257	9,438,009
18	344	Fire Sprinkler Taps	2.59%	2.59%	19,569	(187)		11,123	439,165
19	345	Services	2.59%	2.59%	93,928	(8,393)		43,763	1,732,442
20	346	Meters	2.59%	2.59%	16,380	(23)		10,710	421,705
21	348	Hydrants	2.59%	2.59%	90,660	(608)		20,127	822,140
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				898	34,687
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				9,036	47,178
25	391	Office Furniture & Equipment	2.59%	2.59%	1,483			2,766	107,552
26	393	Warehouse Equipment	2.59%	2.59%				174	6,711
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	2,402	(40)		1,561	61,453
28	395	Laboratory Equipment	2.59%	2.59%				64	2,485
29	396	Power Operated Equipment	2.59%	2.59%		(1,792)		297	10,557
30	397	Communication Equipment	2.59%	2.59%	1,719			2,411	93,958
31	398	Miscellaneous Equipment	2.59%	2.59%	674			315	12,494
32		**TOTAL DIRECT WATER PLANT**			$ 475,933	$ (89,150)	$ (787)	$ 464,303	$ 17,996,536
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 475,933	$ (89,150)	$ (787)	$ 464,303	$ 17,996,536
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(68)	
41									
42		Net (Salvage)/Cost of Removal						743	
43		Accumulated Depreciation						(4,253,512)	$ (4,253,512)
44		Accumulated Depreciation - PTYP						-	$ -
45		RUCO Total Accumulated Depreciation - Calculated						(4,253,512)	$ (4,253,512)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(4,254,531)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (4,253,512)	$ 1,019
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2002 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2002
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	935
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	5,922			-	16,940
5	310.3	Other Source of Supply Land	0.00%	0.00%	85,541			-	135,527
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	18,027			50,091	1,943,017
8	320	Pumping Plant Land	0.00%	0.00%				-	3,805
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	1,158			1,761	68,580
10	325	Electric Pumping Equipment	2.59%	2.59%	87,963	(1,000)		34,711	1,383,669
11	328	Gas Engine Equipment	2.59%	2.59%				6	223
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				1,444	55,744
14	332	Water Treatment Equipment	2.59%	2.59%	8,389	(45,248)		4,949	172,661
15	340	Transmission and Distribution Land	0.00%	0.00%				-	112,947
16	342	Storage Tanks	2.59%	2.59%	314			26,751	1,033,016
17	343	Transmission & Distribution Mains	2.59%	2.59%	317,091	(10,679)		248,412	9,744,421
18	344	Fire Sprinkler Taps	2.59%	2.59%	32,510			11,795	471,676
19	345	Services	2.59%	2.59%	144,127	(7,333)		46,642	1,869,236
20	346	Meters	2.59%	2.59%	23,970	(437)		11,227	445,238
21	348	Hydrants	2.59%	2.59%	29,278	(241)		21,669	851,177
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	19,394			1,150	54,081
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				9,036	47,178
25	391	Office Furniture & Equipment	2.59%	2.59%	3,336			2,829	110,888
26	393	Warehouse Equipment	2.59%	2.59%				174	6,711
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	5,847			1,667	67,300
28	395	Laboratory Equipment	2.59%	2.59%	1,818			88	4,303
29	396	Power Operated Equipment	2.59%	2.59%	1,221			289	11,778
30	397	Communication Equipment	2.59%	2.59%	26,794			2,780	120,752
31	398	Miscellaneous Equipment	2.59%	2.59%	8,026			428	20,520
32		TOTAL DIRECT WATER PLANT			$ 820,725	$ (64,938)	$ -	$ 477,899	$ 18,752,323
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 820,725	$ (64,938)	$ -	$ 477,899	$ 18,752,323
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(68)	
41									
42		Net (Salvage)/Cost of Removal						14,346	
43		Accumulated Depreciation						(4,652,195)	$ (4,652,195)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(4,652,195)	(4,652,195)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(4,653,246)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (4,652,195)	$ 1,051
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2003 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2003
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				14	935
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	9,741			-	26,681
5	310.3	Other Source of Supply Land	0.00%	0.00%	5,500			-	141,027
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	1,114,941			64,763	3,057,958
8	320	Pumping Plant Land	0.00%	0.00%				-	3,805
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	521			1,783	69,101
10	325	Electtric Pumping Equipment	2.59%	2.59%	235,612			38,888	1,619,281
11	328	Gas Engine Equipment	2.59%	2.59%				6	223
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	10,733			1,583	66,477
14	332	Water Treatment Equipment	2.59%	2.59%	8,846			4,586	181,507
15	340	Transmission and Distribution Land	0.00%	0.00%				-	112,947
16	342	Storage Tanks	2.59%	2.59%	(108)			26,754	1,032,908
17	343	Transmission & Distribution Mains	2.59%	2.59%	388,960	(1,827)		257,394	10,131,554
18	344	Fire Sprinkler Taps	2.59%	2.59%	61,229			13,009	532,904
19	345	Services	2.59%	2.59%	181,307	(8,876)		50,646	2,041,667
20	346	Meters	2.59%	2.59%	32,597	(613)		11,946	477,222
21	348	Hydrants	2.59%	2.59%	119,886	(2,099)		23,571	968,964
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				1,401	54,081
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				3,785	47,178
25	391	Office Furniture & Equipment	2.59%	2.59%	3,614			2,919	114,502
26	393	Warehouse Equipment	2.59%	2.59%				174	6,711
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	4,894			1,806	72,194
28	395	Laboratory Equipment	2.59%	2.59%	934			124	5,237
29	396	Power Operated Equipment	2.59%	2.59%	1,021			318	12,799
30	397	Communication Equipment	2.59%	2.59%	8,022			3,231	128,775
31	398	Miscellaneous Equipment	2.59%	2.59%	5,296			600	25,816
32		TOTAL DIRECT WATER PLANT			$ 2,193,545	$ (13,415)	$ -	$ 509,301	$ 20,932,453
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		RUCO Total Water Plant In Service			$ 2,193,545	$ (13,415)	$ -	$ 509,301	$ 20,932,453
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(68)	
41									
42		Net (Salvage)/Cost of Removal						76	
43		Accumulated Depreciation						(5,148,073)	$ (5,148,073)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(5,148,073)	(5,148,073)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(5,149,124)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (5,148,073)	$ 1,051
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				14	935
3	303	Other Intangibles	See Acct. 111	See Acct. 111	1,579			-	1,579
4	310.1	Water Rights	0.00%	0.00%	5,501			-	32,182
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	141,027
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	18,771			79,444	3,076,729
8	320	Pumping Plant Land	0.00%	0.00%				-	3,805
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	1,577			1,810	70,678
10	325	Electtric Pumping Equipment	2.59%	2.59%	144,615	(76,153)		42,826	1,687,743
11	328	Gas Engine Equipment	2.59%	2.59%				6	223
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	26,200			2,061	92,677
14	332	Water Treatment Equipment	2.59%	2.59%	2,326			4,731	183,833
15	340	Transmission and Distribution Land	0.00%	0.00%				-	112,947
16	342	Storage Tanks	2.59%	2.59%				26,752	1,032,908
17	343	Transmission & Distribution Mains	2.59%	2.59%	239,661	(13,673)	(9,032)	265,217	10,348,510
18	344	Fire Sprinkler Taps	2.59%	2.59%	33,156			14,232	566,060
19	345	Services	2.59%	2.59%	125,029	(7,692)		54,399	2,159,004
20	346	Meters	2.59%	2.59%	13,336			12,533	490,557
21	348	Hydrants	2.59%	2.59%	111,957			26,546	1,080,922
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	2,694			1,436	56,776
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	47,178
25	391	Office Furniture & Equipment	2.59%	2.59%	2,063	(200)		2,990	116,364
26	393	Warehouse Equipment	2.59%	2.59%	1,573			194	8,284
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	1,448			1,889	73,642
28	395	Laboratory Equipment	2.59%	2.59%	962			148	6,199
29	396	Power Operated Equipment	2.59%	2.59%	1,205			347	14,004
30	397	Communication Equipment	2.59%	2.59%				3,335	128,775
31	398	Miscellaneous Equipment	2.59%	2.59%	1,404			687	27,220
32		**TOTAL DIRECT WATER PLANT**			$ 735,057	$ (97,718)	$ (9,032)	$ 541,596	$ 21,560,760
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 735,057	$ (97,718)	$ (9,032)	$ 541,596	$ 21,560,760
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(68)	
41									
42		Net (Salvage)/Cost of Removal						(11)	
43		Accumulated Depreciation						(5,592,029)	$ (5,592,029)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(5,592,029)	(5,592,029)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(5,593,081)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (5,592,029)	$ 1,052
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				48	935
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	1,579
4	310.1	Water Rights	0.00%	0.00%	9,901			-	42,083
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	141,027
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	1,858,730			103,758	4,935,459
8	320	Pumping Plant Land	0.00%	0.00%				-	3,805
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	41			1,831	70,719
10	325	Electric Pumping Equipment	2.59%	2.59%	430,486	(178,888)		46,971	1,939,341
11	328	Gas Engine Equipment	2.59%	2.59%				6	223
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	65,061			3,243	157,738
14	332	Water Treatment Equipment	2.59%	2.59%	1,244			4,777	185,077
15	340	Transmission and Distribution Land	0.00%	0.00%				-	112,947
16	342	Storage Tanks	2.59%	2.59%	370			26,757	1,033,277
17	343	Transmission & Distribution Mains	2.59%	2.59%	560,111	(2,606)		275,246	10,906,015
18	344	Fire Sprinkler Taps	2.59%	2.59%	18,451			14,900	584,511
19	345	Services	2.59%	2.59%	210,652	(8,221)		58,540	2,361,435
20	346	Meters	2.59%	2.59%	22,337	(2,593)		12,961	510,301
21	348	Hydrants	2.59%	2.59%	77,058	(2,186)		28,965	1,155,794
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	115			1,472	56,891
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	47,178
25	391	Office Furniture & Equipment	2.59%	2.59%	994			3,027	117,358
26	393	Warehouse Equipment	2.59%	2.59%	702			224	8,986
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	1,343	(20)		1,924	74,965
28	395	Laboratory Equipment	2.59%	2.59%				161	6,199
29	396	Power Operated Equipment	2.59%	2.59%	977			375	14,981
30	397	Communication Equipment	2.59%	2.59%	4,439			3,393	133,213
31	398	Miscellaneous Equipment	2.59%	2.59%	2,909			743	30,129
32		TOTAL DIRECT WATER PLANT			$ 3,265,922	$ (194,514)	$ -	$ 589,321	$ 24,632,168
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 3,265,922	$ (194,514)	$ -	$ 589,321	$ 24,632,168
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						(68)	
41									
42		Net (Salvage)/Cost of Removal						-	
43		Accumulated Depreciation						(5,986,905)	$ (5,986,905)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(5,986,905)	(5,986,905)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(5,982,061)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (5,986,905)	$ (4,844)
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				37	935
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	1,579
4	310.1	Water Rights	0.00%	0.00%	16,688			-	58,771
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	141,027
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	(1,215)	(653)		127,804	4,933,591
8	320	Pumping Plant Land	0.00%	0.00%				-	3,805
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	7			1,832	70,726
10	325	Electtric Pumping Equipment	2.59%	2.59%	41,817			50,770	1,981,158
11	328	Gas Engine Equipment	2.59%	2.59%				6	223
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				4,085	157,738
14	332	Water Treatment Equipment	2.59%	2.59%	196,580			7,339	381,657
15	340	Transmission and Distribution Land	0.00%	0.00%				-	112,947
16	342	Storage Tanks	2.59%	2.59%	1,713			26,784	1,034,990
17	343	Transmission & Distribution Mains	2.59%	2.59%	678,208	(10,191)		291,117	11,574,032
18	344	Fire Sprinkler Taps	2.59%	2.59%	7,648			15,238	592,160
19	345	Services	2.59%	2.59%	133,028	(6,692)		62,797	2,487,771
20	346	Meters	2.59%	2.59%	38,191	(130)		13,710	548,362
21	348	Hydrants	2.59%	2.59%	193,266	(270)		32,434	1,348,790
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				1,473	56,891
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	2,460			137	49,638
25	391	Office Furniture & Equipment	2.59%	2.59%	5,949	(300)		3,113	123,008
26	393	Warehouse Equipment	2.59%	2.59%				233	8,986
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	6,496			2,026	81,461
28	395	Laboratory Equipment	2.59%	2.59%	2,189			189	8,388
29	396	Power Operated Equipment	2.59%	2.59%	6,501			472	21,482
30	397	Communication Equipment	2.59%	2.59%	7,860			3,552	141,073
31	398	Miscellaneous Equipment	2.59%	2.59%				780	30,129
32		**TOTAL DIRECT WATER PLANT**			$ 1,337,388	$ (18,236)	$ -	$ 645,929	$ 25,951,319
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 1,337,388	$ (18,236)	$ -	$ 645,929	$ 25,951,319
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						(7)	
43		Accumulated Depreciation						(6,614,604)	$ (6,614,604)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(6,614,604)	(6,614,604)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(6,609,761)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (6,614,604)	$ (4,843)
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				37	935
3	303	Other Intangibles	See Acct. 111	See Acct. 111				79	1,579
4	310.1	Water Rights	0.00%	0.00%	27,898			-	86,669
5	310.3	Other Source of Supply Land	0.00%	0.00%	39,027		(18,215)	-	161,839
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	1,433,375	(1,111,876)		131,943	5,255,089
8	320	Pumping Plant Land	0.00%	0.00%				-	3,805
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				1,832	70,726
10	325	Electtric Pumping Equipment	2.59%	2.59%	357,545	(147,061)		54,038	2,191,642
11	328	Gas Engine Equipment	2.59%	2.59%				6	223
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	9,964			4,214	167,702
14	332	Water Treatment Equipment	2.59%	2.59%	240,226			12,996	621,884
15	340	Transmission and Distribution Land	0.00%	0.00%				-	112,947
16	342	Storage Tanks	2.59%	2.59%	237,733			29,885	1,272,723
17	343	Transmission & Distribution Mains	2.59%	2.59%	5,241,741	(33,285)	(2,216,972)	338,507	14,565,516
18	344	Fire Sprinkler Taps	2.59%	2.59%	29,662	(874)		15,710	620,948
19	345	Services	2.59%	2.59%	387,072	(10,711)		69,307	2,864,132
20	346	Meters	2.59%	2.59%	15,604			14,405	563,966
21	348	Hydrants	2.59%	2.59%	110,470	(2,797)		36,328	1,456,462
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	75,400			2,450	132,291
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	317			1,696	49,955
25	391	Office Furniture & Equipment	2.59%	2.59%	14,060			3,368	137,068
26	393	Warehouse Equipment	2.59%	2.59%	16,788			450	25,774
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	425	(29)		2,115	81,858
28	395	Laboratory Equipment	2.59%	2.59%	3,140	(1,635)		237	9,894
29	396	Power Operated Equipment	2.59%	2.59%				556	21,482
30	397	Communication Equipment	2.59%	2.59%	6,187			3,734	147,260
31	398	Miscellaneous Equipment	2.59%	2.59%				780	30,129
32		**TOTAL DIRECT WATER PLANT**			$ 8,246,634	$ (1,308,268)	$ (2,235,186)	$ 724,673	$ 30,654,499
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 8,246,634	$ (1,308,268)	$ (2,235,186)	$ 724,673	$ 30,654,499
35									
36		**Company Direct Plant As Filed**							30,654,499
37									
38		**RUCO Direct Plant Adjustment**							$ (0)
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						-	
43		Accumulated Depreciation						(6,031,009)	$ (6,031,009)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(6,031,009)	(6,031,009)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(6,026,166)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (6,031,009)	$ (4,843)
49									
50		**RUCO Net Adjustment**							$ (4,844)
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2003 12/31/2003 Per Decision 68302	ADJ-1 Remove Post Test Year Plant	Balance 12/31/2003
1	301	Organization	0.00%	651		651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.	8,496		8,496
4	310.1	Water Rights	0.00%	-		-
5	310.3	Other Source of Supply Land	0.00%	-		-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
7	314	Wells	2.59%	-		-
8	320	Pumping Plant Land	0.00%	-		-
9	321	Pumping Plant Structures and Improvements	2.59%	-		-
10	325	Electric Pumping Equipment	2.59%	-		-
11	328	Gas Engine Equipment	2.59%	-		-
12	330	Water Treatment Plant Land	0.00%	-		-
13	331	Water Treatment Structures and Improvements	2.59%	-		-
14	332	Water Treatment Equipment	2.59%	-		-
15	340	Transmission and Distribution Land	0.00%	-		-
16	342	Storage Tanks	2.59%	-		-
17	343	Transmission and Distribution Mains	2.59%	-		-
18	344	Fire Sprinkler Taps	2.59%	-		-
19	345	Services	2.59%	-		-
20	346	Meters	2.59%	-		-
21	348	Hydrants	2.59%	-		-
22	389	General Plant Land	0.00%	-		-
23	390	General Plant Structures	2.59%	31,795		31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	1,267,373		1,267,373
25	391	Office Furniture and Equipment	2.59%	3,505,411		3,505,411
26	393	Warehouse Equipment	2.59%	3,705		3,705
27	394	Tools, Shop and Garage Equipment	2.59%	30,450		30,450
28	395	Laboratory Equipment	2.59%	977		977
29	396	Power Operated Equipment	2.59%	-		-
30	397	Communication Equipment	2.59%	143,052		143,052
31	398	Miscellaneous Equipment	2.59%	7,207		7,207
32		**TOTAL PHOENIX OFFICE PLANT**		4,999,117	-	4,999,117
33		Post Test Year Plant (PTYP)		-	-	-
34		**RUCO Total Phoenix Office**		4,999,117	-	4,999,117
35						
36		**Company Phoenix Office As Filed**		4,999,117		4,999,117
37						
38		RUCO Phoenix Office Plant Adjustment		-		-
39						
40		Reserve Deficiency Accrual - Dec. 38733		-		-
41						
42		Net (Salvage)/Cost of Removal				
43		Accumulated Depreciation		(503,775)	-	(503,775)
44		Accumulated Depreciation - PTYP		-	-	-
45		RUCO Total Accumulated Depreciation - Calculated		(503,775)	-	(503,775)
46						
47		Company As Filed - Accumulated Depreciation				(503,775)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**				-
49						
50		**RUCO Net Adjustment**				
51						
52						
53						
54						
55						

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	48,512			78,228	1,315,885
25	391	Office Furniture and Equipment	2.59%	129,135	(7,465)		92,366	3,627,081
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	24,820			1,110	55,270
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	6,465			3,789	149,517
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		208,932	(7,465)	-	176,624	5,200,584
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,200,584
35								
36		**Company Phoenix Office As Filed**						5,200,584
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(672,934)	(672,934)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(672,934)	(672,934)
46								
47		Company As Filed - Accumulated Depreciation						(672,934)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(0)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				89,580	1,315,885
25	391	Office Furniture and Equipment	2.59%	221,339			96,808	3,848,420
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	20,585			1,698	75,855
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	885			3,884	150,402
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		242,809	-	-	193,101	5,443,393
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,443,393
35								
36		**Company Phoenix Office As Filed**						5,443,393
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(866,035)	(866,035)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(866,035)	(866,035)
46								
47		Company As Filed - Accumulated Depreciation						(866,035)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				94,864	1,315,885
25	391	Office Furniture and Equipment	2.59%	369,071			104,454	4,217,491
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	59,519			2,735	135,374
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	1,741			3,918	152,143
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		430,332	-	-	207,102	5,873,725
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,873,725
35								
36		**Company Phoenix Office As Filed**						5,873,725
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(1,073,138)	(1,073,138)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(1,073,138)	(1,073,138)
46								
47		Company As Filed - Accumulated Depreciation						(1,073,137)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(1)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				425	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	10,463			959	42,258
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	93			86,708	1,315,978
25	391	Office Furniture and Equipment	2.59%	464,535	(243,714)		112,093	4,438,312
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	40,312			4,028	175,686
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	4,089			3,993	156,232
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		TOTAL PHOENIX OFFICE PLANT		519,493	(243,714)	-	208,514	6,149,503
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						6,149,503
35								
36		**Company Phoenix Office As Filed**						6,149,503
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(1,037,938)	(1,037,938)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(1,037,938)	(1,037,938)
46								
47		Company As Filed - Accumulated Depreciation						(1,036,382)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(1,556)
49								
50		**RUCO Net Adjustment**						(1,556)
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2003 12/31/2003 Per Decision 68302	2003 ADJ-1 Remove Post Test Year Plant	2003 Balance 12/31/2003
1	301	Organization	0.00%	-		-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
4	310.1	Water Rights	0.00%	-		-
5	310.3	Other Source of Supply Land	0.00%	80		80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
7	314	Wells	2.59%	-		-
8	320	Pumping Plant Land	0.00%	-		-
9	321	Pumping Plant Structures and Improvements	2.59%	-		-
10	325	Electric Pumping Equipment	2.59%	-		-
11	328	Gas Engine Equipment	2.59%	-		-
12	330	Water Treatment Plant Land	0.00%	-		-
13	331	Water Treatment Structures and Improvements	2.59%	-		-
14	332	Water Treatment Equipment	2.59%	2,050		2,050
15	340	Transmission and Distribution Land	0.00%	-		-
16	342	Storage Tanks	2.59%	-		-
17	343	Transmission and Distribution Mains	2.59%	6,066		6,066
18	344	Fire Sprinkler Taps	2.59%	-		-
19	345	Services	2.59%	-		-
20	346	Meters	2.59%	-		-
21	348	Hydrants	2.59%	-		-
22	389	General Plant Land	0.00%	-		-
23	390	General Plant Structures	2.59%	37,472		37,472
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	-		-
25	391	Office Furniture and Equipment	2.59%	3,983		3,983
26	393	Warehouse Equipment	2.59%	1,088		1,088
27	394	Tools, Shop and Garage Equipment	2.59%	58,430		58,430
28	395	Laboratory Equipment	2.59%	2,981		2,981
29	396	Power Operated Equipment	2.59%	1,458		1,458
30	397	Communication Equipment	2.59%	-		-
31	398	Miscellaneous Equipment	2.59%	-		-
32		**TOTAL METER SHOP PLANT**		113,608	-	113,608
33		Post Test Year Plant (PTYP)		-	-	-
34		**RUCO Total Meter Shop**		113,608	-	113,608
35						
36		**Company Meter Shop As Filed**		113,608		113,608
37						
38		RUCO Meter Shop Plant Adjustment		-		-
39						
40		Reserve Deficiency Accrual - Dec. 38733				
41						
42		Net (Salvage)/Cost of Removal				
43		Accumulated Depreciation		(30,118)	-	(30,118)
44		Accumulated Depreciation - PTYP		-	-	-
45		RUCO Total Accumulated Depreciation - Calculated		(30,118)	-	(30,118)
46						
47		Company As Filed - Accumulated Depreciation				(30,118)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**				-
49						
50		**RUCO Net Adjustment**				
51						
52						
53						
54						
55						
56	Notes					
57	Acct. 302 - Franchises amortized over 25 years.					
58	Acct. 303 - Other intangibles amortized over 15 & 20 Years.					
59	Acct. 310.4 - Wells - Other amortized over 24 years.					
60	Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.					

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	12,809			1,136	50,281
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				-	-
25	391	Office Furniture and Equipment	2.59%	3,166			144	7,149
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	1,575			1,534	60,005
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		17,550	-	-	3,168	131,158
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						131,158
35								
36		**Company Meter Shop As Filed**						131,158
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733						
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(33,286)	(33,286)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(33,286)	(33,286)
46								
47		Company As Filed - Accumulated Depreciation						(33,286)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				1,302	50,281
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				-	-
25	391	Office Furniture and Equipment	2.59%	94			186	7,243
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	2,004			1,580	62,009
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		2,097	-	-	3,422	133,256
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						133,256
35								
36		**Company Meter Shop As Filed**						133,256
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(36,708)	(36,708)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(36,708)	(36,708)
46								
47		Company As Filed - Accumulated Depreciation						(36,708)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	2,571			1,336	52,852
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				-	-
25	391	Office Furniture and Equipment	2.59%	1,610			208	8,853
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	3,115			1,646	65,124
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		7,296	-	-	3,544	140,551
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						140,551
35								
36		**Company Meter Shop As Filed**						140,551
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(40,251)	(40,251)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(40,251)	(40,251)
46								
47		Company As Filed - Accumulated Depreciation						(40,251)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						(0)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				1,369	52,852
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				-	-
25	391	Office Furniture and Equipment	2.59%	1,893			254	10,745
26	393	Warehouse Equipment	2.59%	1,089			42	2,177
27	394	Tools, Shop and Garage Equipment	2.59%	2,298			1,716	67,422
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		5,280	-	-	3,707	145,832
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						145,832
35								
36		**Company Meter Shop As Filed**						145,832
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(43,958)	(43,958)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(43,958)	(43,958)
46								
47		Company As Filed - Accumulated Depreciation						(43,959)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						1
49								
50		**RUCO Net Adjustment**						1
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

EXPLANATION OF RATE BASE ADJUSTMENT NO. 2
POST TEST-YEAR PLANT - PHOENIX OFFICE

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) COMPANY ADJUSTED TY PLANT	(B) POST TY ADDITIONS	(C) 3-FACTOR ALLOCATOR	(D) REMOVE PTY PLANT
1	301	Organization	$ 55	$ -	8.45%	$ -
2	302	Franchises	935	-	8.45%	-
3	303	Other Intangibles	2,297	-	8.45%	-
4	310.1	Water Rights	86,669	-	8.45%	-
5	310.3	Other Source of Supply Land	161,846	-	8.45%	-
6	310.4	Wells - Other	-	-	8.45%	-
7	314	Wells	5,668,874	-	8.45%	-
8	320	Pumping Plant Land	3,805	-	8.45%	-
9	321	Pumping Plant Structures & Imprm'ts	70,726	-	8.45%	-
10	325	Electtric Pumping Equipment	2,191,674	-	8.45%	-
11	328	Gas Engine Equipment	223	-	8.45%	-
12	330	Water Treatment Plant Land	-	-	8.45%	-
13	331	Water Treatment Structures & Imprm'ts	167,702	-	8.45%	-
14	332	Water Treatment Equipment	1,129,423	-	8.45%	-
15	340	Transmission and Distribution Land	112,947	-	8.45%	-
16	342	Storage Tanks	1,272,723	-	8.45%	-
17	343	Transmission & Distribution Mains	16,783,007	-	8.45%	-
18	344	Fire Sprinkler Taps	620,948	-	8.45%	-
19	345	Services	2,864,132	-	8.45%	-
20	346	Meters	563,966	-	8.45%	-
21	348	Hydrants	1,456,462	-	8.45%	-
22	389	General Plant Land	-	-	8.45%	-
23	390	General Plant Structures	140,328	-	8.45%	-
24	390.1	Leasehold Improvements	161,155	-	8.45%	-
25	391	Office Furniture & Equipment	513,013	120,057	8.45%	10,145
26	393	Warehouse Equipment	26,271	-	8.45%	-
27	394	Tools, Shop & Garage Equipment	102,400	-	8.45%	-
28	395	Laboratory Equipment	10,228	-	8.45%	-
29	396	Power Operated Equipment	21,605	-	8.45%	-
30	397	Communication Equipment	160,462	-	8.45%	-
31	398	Miscellaneous Equipment	30,738	-	8.45%	-
32						
33		**TOTAL PTY WATER PLANT**	$ 34,324,616	$ 120,057		$ 10,145
34		Company As Filed	$ 34,324,616	120,057		10,145
35		Difference	$ -	$ -		$ -
36						
37		RUCO PTY Plant Adjustment				$ (10,145)
38						
39		RUCO PTY Accumulated Depreciation Plant Adjustment				$ 338
40						
41						
42		References:				
43		Column (A): Company Schedules B-2				
44		Column (B): Post Test Year Phoenix Office Plant Allocation				
45		Column (C): 3-Factor Allocator				
46		Column (D): Adjustment				

EXPLANATION OF RATE BASE ADJUSTMENT NO. 6
ALLOWANCE FOR WORKING CAPITAL

LINE NO.	DESCRIPTION	(A) AMOUNT	(B) REFERENCE
1	Working Cash Requirement Per Company	$ 87,691	Company Schedule B-5, PG. 1
2	Working Cash Requirement Per RUCO	(130,629)	RUCO Schedule WAR-5, Page 2
3	Adjustment	$ (218,320)	Line 2 - Line 1
4	Material and Supplies Inventories Per Company	$ 51,656	Company Schedule B-5, PG. 1
5	Material and Supplies Inventories Per RUCO	51,656	Company Schedule B-5, PG. 1
6	Adjustment	$ -	Line 5 - Line 4
7	Required Bank Balances Per Company	$ 43,468	Company Schedule B-5, PG. 1
8	Required Bank Balances Per RUCO	43,468	Company Schedule B-5, PG. 1
9	Adjustment	$ -	Line 8 - Line 7
10	Prepayments & Special Deposits Per Company	$ 45,383	Company Schedule B-5, PG. 1
11	Prepayments & Special Deposits Per RUCO	45,383	Company Schedule B-5, PG. 1
12	Adjustment	$ -	Line 11 - Line 10
13	TOTAL ADJUSTMENT (See WAR-2, Column (K))	$ (218,320)	Sum of Lines 3, 6, 9 & 12

EXPLANATION OF RATE BASE ADJUSTMENT NO. 6 - CONT'D
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
	Operating Expenses					
1	Purchased Power	$ 518,834	$ -	$ 518,834	35.92	$ 18,636,517
2	Payroll	42,663	(25,582)	17,081	14.00	239,136
3	Purchased Water	-	-	-	-	-
4	Chemicals	8,650	-	8,650	20.43	176,679
5	Property & Liability Insurance	25,243	-	25,243	(45.27)	(1,142,751)
6	Workman's Compensation Insurance	12,619	-	12,619	(46.50)	(586,784)
7	Health Insurance	170,235	(84)	170,151	(8.92)	(1,517,750)
8	Other Operating & Maintenance Expenses	1,462,349	(14,083)	1,448,266	30.00	43,447,980
9	Federal Current Income Taxes	566,716	(256,841)	309,875	37.00	11,465,385
10	State Current Income Taxes	124,842	(56,579)	68,263	37.00	2,525,722
11	FICA Taxes	56,756	(4,067)	52,689	14.00	737,644
12	FUTA & SUTA Taxes	1,358	-	1,358	83.10	112,850
13	Property Taxes	125,837	(12,297)	113,540	212.00	24,070,454
14	Registration, Svc. Contracts, & Misc. Fees	48,046	-	48,046	(98.83)	(4,748,386)
15	Retirement Annuities (401k)	56,189	(2,077)	54,111	34.72	1,878,748
16	Subtotal	3,220,336	(371,610)	2,848,726		95,295,443
17	Synchronized Interest	$ 668,291	$ (124,076)	$ 544,215	91.25	$ 49,659,615
18	Cost of Equity	1,100,095	(1,100,095)	-	-	-
19	Subtotal	$ 1,768,386	$ (1,224,171)	$ 544,215		$ 49,659,615
20	Total	$ 4,988,722	$ (1,595,781)	$ 3,392,941		$ 144,955,058

21	Expense Lag	Line 17, Col. (E) / (C)	42.72
22	Revenue Lag	Company B-5 Schedules	28.67
23	Net Lag	Line 18 - Line 17	(14.05)
24	RUCO Adjusted Expenses	Col. (C), Line 16	$ 3,392,941
25	Cash Working Capital	Line 19 X Line 20 / 365 Days	(130,629)
26	Company As Filed	Co. Schedule B-6, Page 1	87,691
27	Difference	Line 21 - Line 22	$ (218,320)
28	ADJUSTMENT	Line 27	$ (218,320)

NOTE: Expense Lag Days Used in the Last Western Group Rate Case.

NOTE: RUCO reviewed several invoices from a number of companies with terms of net 30 days.

References:
Column (A): - Company Schedule B-5
Column (B): RUCO Operating Income Adjustments (See Schedule WAR-7)
Column (C): Column (A) + (B)
Column (D): - Company Schedule B-5
Column (E): Column (C) X Column (D)

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 2,500,263	$ (1,731)	$ 2,498,532	$ 581,668	$ 3,080,200
2	Commercial	957,571	(828)	956,743	351,686	1,308,430
3	Industrial	315	2	317	(22)	295
4	Private Fire Service	7,692	-	7,692	30,758	38,450
5	Other Water Revenues	26,716	(30)	26,686	11,149	37,835
6	Total Water Revenues	$ 3,492,558	$ (2,587)	$ 3,489,970	$ 975,239	$ 4,465,209
7	Miscellaneous	$ 28,567	$ -	$ 28,567	$ 306	$ 28,873
8	Total Operating Revenues	$ 3,521,124	$ (2,587)	$ 3,518,537	$ 975,545	$ 4,494,082
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	7,247	-	7,247	-	7,247
11	Pumping Expenses:	-				
12	Purchased Power	518,834	-	518,834	-	518,834
13	Purchased Gas	2,626	-	2,626	-	2,626
14	Other	129,182	-	129,182	-	129,182
15	Water Treatment Expenses	319,722	-	319,722	-	319,722
16	Transmission & Distribution Expenses	400,194	-	400,194	-	400,194
17	Customer Accounting Expenses	323,108	-	323,108	-	323,108
18	Sales Expense	2,838	-	2,838	-	2,838
19	Administrative & General Expenses	641,077	(145,009)	496,067	-	496,067
20	Total Operations & Maintenance Expense	$ 2,344,827	$ (145,009)	$ 2,199,817	$ -	$ 2,199,817
21	Depreciation & Amortization Expenses	$ 731,033	$ (117,962)	$ 613,071	$ -	$ 613,071
	Taxes					
22	Federal Income Taxes	$ (125,482)	$ 126,784	$ 1,302	$ 308,573	$ 309,875
23	State Income Taxes	(27,643)	27,929	287	67,976	68,263
24	Property Taxes	125,837	(12,297)	113,540	-	113,540
25	Other	47,845	(4,067)	43,778	-	43,778
26	Total Taxes	$ 20,557	$ 138,349	$ 158,906	$ 376,549	$ 535,456
27	Total Operating Expenses	$ 3,096,417	$ (124,622)	$ 2,971,795	$ 376,549	$ 3,348,344
28	Operating Income	$ 424,708	$ 122,034	$ 546,742	$ 598,995	$ 1,145,738

References:
Column (A): Company Schedule C-1
Column (B): WAR-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): WAR-1
Column (E): Column (C) + Column (D)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Sedona System
Schedule WAR-8
Page 1 of 1

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 2,500,263	$ -	$ -	$ -	$ -	$ (1,731)	$ -	$ -	$ -	$ -	$ -	$ 2,498,532
2	Commercial	957,571	-	-	-	-	(828)	-	-	-	-	-	956,743
3	Industrial	315	-	-	-	-	2	-	-	-	-	-	317
4	Private Fire Service	7,692	-	-	-	-	-	-	-	-	-	-	7,692
5	Other Water Revenues	26,716	-	-	-	-	(30)	-	-	-	-	-	26,686
6	Total Water Revenues	$ 3,492,558	$ -	$ -	$ -	$ -	$ (2,587)	$ -	$ -	$ -	$ -	$ -	$ 3,489,970
7	Miscellaneous	$ 28,567	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,567
8	Total Operating Revenues	$ 3,521,124	$ -	$ -	$ -	$ -	$ (2,587)	$ -	$ -	$ -	$ -	$ -	$ 3,518,537
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	7,247	-	-	-	-	-	-	-	-	-	-	7,247
11	Pumping Expenses:					-							
12	Purchased Power	518,834	-	-	-	-	-	-	-	-	-	-	518,834
13	Purchased Gas	2,626	-	-	-	-	-	-	-	-	-	-	2,626
14	Other	129,182	-	-	-	-	-	-	-	-	-	-	129,182
15	Water Treatment Expenses	319,722	-	-	-	-	-	-	-	-	-	-	319,722
16	Transmission & Distribution Expenses	400,194	-	-	-	-	-	-	-	-	-	-	400,194
17	Customer Accounting Expenses	323,108	-	-	-	-	-	-	-	-	-	-	323,108
18	Sales Expense	2,838	-	-	-	-	-	-	-	-	-	-	2,838
19	Administrative & General Expenses	641,077	(25,582)	-	(2,077)	(111,634)	-	(84)	-	-	(5,633)	-	496,067
20	Total Operations & Maintenance Expense	$ 2,344,827	$ (25,582)	$ -	$ (2,077)	$ (111,634)	$ -	$ (84)	$ -	$ -	$ (5,633)	$ -	$ 2,199,817
21	Depreciation & Amortization Expenses	$ 731,033	$ -	$ -	$ -	$ -	$ -	$ -	$ (117,962)	$ -	$ -	$ -	$ 613,071
	Taxes												
22	Federal Income Taxes	$ (125,482)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 126,784	$ 1,302
23	State Income Taxes	(27,643)	-	-	-	-	-	-	-	-	-	27,929	287
24	Property Taxes	125,837	-	-	-	-	-	-	-	(12,297)	-	-	113,540
25	Other	47,845	-	(4,067)	-	-	-	-	-	-	-	-	43,778
26	Total Taxes	$ 20,557	$ -	$ (4,067)	$ -	$ -	$ -	$ -	$ -	$ (12,297)	$ -	$ 154,714	$ 158,906
27	Total Operating Expenses	$ 3,096,417	$ (25,582)	$ (4,067)	$ (2,077)	$ (111,634)	$ -	$ (84)	$ (117,962)	$ (12,297)	$ (5,633)	$ 154,714	$ 2,971,795
28	Operating Income	$ 424,708	$ 25,582	$ 4,067	$ 2,077	$ 111,634	$ (2,587)	$ 84	$ 117,962	$ 12,297	$ 5,633	$ (154,714)	$ 546,742

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule WAR-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule WAR-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule WAR-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule WAR-10
7 - Depreciation Expense	Testimony, WAR And Schedule WAR-11
8 - Property Tax Expense	Testimony, WAR And Schedule WAR-12
9 - Rate Case Expense	Testimony, WAR And Schedule WAR-13
10 - Income Tax	Testimony, WAR And Schedule WAR-14

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
PAYROLL EXPENSE

LINE NO.	DESCRIPTION		(A) PER RUCO DR 1.11.d
1	Normalize Over-Time Over 4 Years:		
2	2005 OT Hours		15,008.5
3	2006 OT Hours		18,080.0
4	2007 OT Hours		28,132.5
5	2008 OT Hours		17,530.0
6			
7	Total OT Hours for 2005 - 2008		78,751.0
8	Divided by 4 Years		4
9			
10	Normalized Level of OT Hours/Yr.		19,687.8
11			
12	OT Hours in Test Year		28,132.5
13			
14	Amount of Abnormal TY OT Hours		8,444.8
15			
16	Multiplied by Average OT Hrly. Rate	**See NOTE**	35.85
17			
18	Total Abnormal OT Dollars in TY		$ 302,744
19			
20	3-Factor Allocator Per District		8.45%
21			
22	RUCO Adjustment		$ (25,582)
23			
24			
25			
26			
27			

28	3-Factor Allocator By District:			
29	Superstition	24.94%	White Tank	2.37%
30	Bisbee	4.98%	Ajo	0.81%
31	Sierra Vista	2.58%	Coolidge	5.27%
32	San Manuel	1.68%	Lakeside	6.20%
33	Oracle	2.28%	Overgaard	3.99%
34	Winkelman	0.22%	Sedona	8.45%
35	Miami	4.98%	Pinewood	2.95%
36	Casa Grande	26.55%	Rimrock	1.48%
37	Stanfield	0.27%		
38				
39				
40				
41				
42	**Calculation Notes:**			
43	Average of Hourly Rate	$ 21.65		
44	OT Hourly Rate 1.5	32.48		

NOTE: The Company calculated the average hourly rate for overtime in response to data request AII-11.6 to be $35.85. RUCO accepts that rate in making its payroll adjustments.

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PAYROLL TAX EXPENSE ASSOCIATED WITH RUCO ADJUSTMENT 1

LINE NO.	DESCRIPTION	(A) PER RUCO DR 1.11.d
1	Payroll Tax Expense:	
2		
3	Total Abnormal OT Dollars in TY	$ 302,744
4		
5	3-Factor Allocator Per District	8.45%
6		
7	RUCO Allocated Payroll by District	$ 25,582
8		
9	Payroll Tax Expense Allocator By Group:	
10		
11	RUCO Payroll Tax Expense Allocator by Group	15.90%
12		
13	RUCO Payroll Tax Expense Adjustment	$ (4,067)
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Payroll Tax Expense Allocator By Group:	
39	Eastern Group	7.47%
40	Western Group	11.65%
41	Northern Group	15.90%

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
PAYROLL 401(K) EXPENSE ASSOCIATED WITH RUCO ADJUSTMENT 1

LINE NO.	DESCRIPTION	(A) PER RUCO DR 1.11.d
1	Payroll 401(K) Expense:	
2		
3	Total Abnormal OT Dollars in TY	$ 302,744
4		
5	3-Factor Allocator Per District	8.45%
6		
7	RUCO Allocated Payroll by District	$ 25,582
8		
9	Payroll 401(K) Expense Allocator By Group:	
10		
11	RUCO Payroll 401(K) Expense Allocator by Group	8.12%
12		
13	RUCO Payroll 401(K) Expense Adjustment	$ (2,077)
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Payroll Tax Expense Allocator By Group:	
39	Eastern Group	8.39%
40	Western Group	8.45%
41	Northern Group	8.12%

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
INSURANCE EXPENSE

LINE NO.		(A) INCREASE/ (DECREASE) LONG-TERM DISABILITY PER COMPANY	(B) RUCO ADJUSTMENT	(C) INCREASE/ (DECREASE) LONG-TERM DISABILITY PER RUCO	
1	System				
2					
3	Eastern Group				
4	Supersition	$ 2,224	$ (273)	$ 1,950	
5	Apache Junction				
6	Superior				
7	Bisbee	122	(45)	77	
8	Sierra Vista	115	(38)	77	
9	San Manuel	5	(20)	(16)	
10	Oracle	25	(20)	5	
11	Saddlebrook	5	(0)	4	
12	Winkelman	0	(2)	(2)	
13	Miami	(338)	(40)	(378)	
14	Subtotal	$ 2,157	$ (439)	$ 1,718	
15					
16	Western Group				
17	Casa Grande	2,137	(298)	1,839	
18	Stanfield	20	(3)	17	
19	White Tank	148	(22)	126	
20	Ajo	58	(9)	49	
21	Coolidge	(127)	(62)	(189)	
22	Subtotal	$ 2,235	$ (393)	$ 1,842	
23					
24	Northern Group				
25	Lakeside	570	(65)	506	
26	Overgaard	507	(55)	452	
27	Sedona	445	(84)	361	
28	Pinewood	199	(38)	162	
29	Rimrock	87	(16)	71	
30	Subtotal	$ 1,809	$ (257)	$ 1,551	
31					
32					
33	Total Company	$ 6,201	$ (1,090)	$ 5,111	(a)

REFERENCE

COLUMN (A): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD
COLUMN (B): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD
COLUMN (C): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD

NOTES:

(a) CALCULATED AS FOLLOWS:		PER COMPANY	RUCO ADJUSTMENT	PER RUCO	REFERENCE
1	Current Rate per Payroll Dollar	$ 0.0036		$ 0.0036	COMPANY WORKPAPER - "GROUP INSURANCE" TAB LTD
2	Pro Forma Payroll Dollars	$ 11,095,569	$ 302,744	$ 10,792,825	COMPANY WORKPAPER - "GROUP INSURANCE)
3	Pro Forma LTD - Total Company	$ 39,944		$ 38,854	LINE 1 x LINE 2
4	Y/E Number of Customers	$ 83,825		$ 83,825	COMPANY WORKPAPER - "GROUP INSURANCE)
5	Pro Forma 2007 LTD - Spread	$ 38,854		$ 38,854	COMPANY WORKPAPER - "GROUP INSURANCE)
6	Increase / (Decrease)	$ 6,201		$ 5,111	COMPANY WORKPAPER - "GROUP INSURANCE)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 7
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCOUNT NO.	ACCOUNT NAME	(A) RUCO PLANT VALUE	(B) COMPANY PROPOSED DEP. RATES	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization	$ 55	0.00%	$ -
2	302	Franchises	935	See Acct. 111	-
3	303	Other Intangibles	2,297	See Acct. 111	-
4	310.1	Water Rights	86,669	0.00%	-
5	310.3	Other Source of Supply Land	161,846	0.00%	-
6	310.4	Wells - Other	-	See Acct. 111	-
7	314	Wells	2,271,156	3.13%	71,087
8	320	Pumping Plant Land	3,805	0.00%	-
9	321	Pumping Plant Structures & Imprm'ts	70,726	2.86%	2,023
10	325	Electtric Pumping Equipment	2,184,913	5.88%	128,473
11	328	Gas Engine Equipment	223	4.00%	9
12	330	Water Treatment Plant Land	-	0.00%	-
13	331	Water Treatment Structures & Imprm'ts	167,702	2.50%	4,193
14	332	Water Treatment Equipment	1,129,423	2.86%	32,301
15	340	Transmission and Distribution Land	112,947	0.00%	-
16	342	Storage Tanks	1,272,723	2.00%	25,454
17	343	Transmission & Distribution Mains	16,121,269	1.79%	288,571
18	344	Fire Sprinkler Taps	620,948	2.00%	12,419
19	345	Services	2,864,132	2.38%	68,166
20	346	Meters	563,966	4.55%	25,660
21	348	Hydrants	1,456,462	1.82%	26,508
22	389	General Plant Land	-	0.00%	-
23	390	General Plant Structures	140,328	2.50%	3,508
24	390.1	Leasehold Improvements	161,155	See Acct. 108.2	-
25	391	Office Furniture & Equipment	502,869	6.67%	33,541
26	393	Warehouse Equipment	26,271	5.00%	1,314
27	394	Tools, Shop & Garage Equipment	102,400	4.00%	4,096
28	395	Laboratory Equipment	10,228	5.00%	511
29	396	Power Operated Equipment	21,605	6.67%	1,441
30	397	Communication Equipment	160,462	6.67%	10,703
31	398	Miscellaneous Equipment	30,738	3.33%	1,024
32		Rounding	-		
33		TEST YEAR GROSS PLANT AND DEPRECIATION EXPENSE	$ 30,248,254		$ 741,002
34					
35		AMORTIZATION OF CONTRIBUTIONS	(6,396,542)	2.00%	(127,931)
36		Rounding			-
37	**TOTAL DEPRECIATION EXPENSE**				$ 613,071
38					
39	Company As Filed				731,033
40	Difference				$ (117,962)
41					
42	RUCO Adjustment (See WAR-8, Column (B))				$ (117,962)
43					
44					
45	3-Factor Allocator By District:				
46	Superstition	24.94%	White Tank	2.37%	
47	Bisbee	4.98%	Ajo	0.81%	
48	Sierra Vista	2.58%	Coolidge	5.27%	
49	San Manuel	1.68%	Lakeside	6.20%	
50	Oracle	2.28%	Overgaard	3.99%	
51	Winkelman	0.22%	Sedona	8.45%	
52	Miami	4.98%	Pinewood	2.95%	
53	Casa Grande	26.55%	Rimrock	1.48%	
54	Stanfield	0.27%			

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 8
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A)	(B)
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. WAR-7, Col (C), Ln 8	$ 3,518,537	
2	Adjusted Revenues In Year Ended December 2007	Sch. WAR-7, Col (C), Ln 8	3,518,537	
3	Proposed Revenues	Sch. WAR-7, Col (E), Ln 8	4,494,082	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 11,531,156	
5	Average Annual Operating Revenues	Line 4 / 3	3,843,719	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 7,687,437
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Company Schedule E	$ 3,262,159	
8	10% Of CWIP	Line 7 X 10%		$ 326,216
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	Company Workpapers	$ -	
10	Acc. Dep. Of Transportation Equipment	Company Workpapers	-	
11	Net Book Value Of Transportation Equipment	Line 9 + Line 10		$ (177,913)
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 7,835,740
	Calculation Of The Company's Tax Liability:			
	MULTIPLY:			
	FCV X Valuation Assessment Ratio X Property Tax Rates:			
13	Assessment Ratio	House Bill 2779	22.5%	
14	Assessed Value	Line 12 X Line 13	$ 1,763,042	
	Property Tax Rates:			
15	Primary Tax Rate	Company Workpapers	6.44%	
16	Secondary Tax Rate	Company Workpapers	0.00%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	6.44%	
	Property Tax			$ 113,540
	Tax On Parcel			-
18	Company's Total Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 113,540
19	Test Year Adjusted Property Tax Expense As Filed	Co. Sch. C-1		125,837
20	Decrease In Property Tax Expense	Line 18 - Line 19		$ (12,297)
21	RUCO Adjustment (See WAR-8, Column (C))	Line 20		$ (12,297)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 9
RATE CASE EXPENSE

LINE NO.	DESCRIPTION	(A) COMPANY ESTIMATE	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total	$ 500,000	$ (200,000)	$ 300,000
2	Allocation Factor			8.45%
3	Sedona System (Line 1 X Line 2)			$ 25,350
4	Amortization Period - 3 Years			3
5	RUCO Adjusted Rate Case Expense (Line 3 / 3 Years)			$ 8,450
6	Company Rate Case Expenses As Filed (Company Sch. C-2)			$ 14,083
7	RUCO Pro Forma Rate Case Expense (Lines 5 - 6)			$ (5,633)
8	RUCO Adjustment (Line 7) (See WAR-8, Column (E))			$ (5,633)

3-Factor Allocator By District:

Superstition	24.94%	White Tank	2.37%
Bisbee	4.98%	Ajo	0.81%
Sierra Vista	2.58%	Coolidge	5.27%
San Manuel	1.68%	Lakeside	6.20%
Oracle	2.28%	Overgaard	3.99%
Winkelman	0.22%	Sedona	8.45%
Miami	4.98%	Pinewood	2.95%
Casa Grande	26.55%	Rimrock	1.48%
Stanfield	0.27%		

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 10
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. WAR-7, Column (C), L28 + L22 + L23	$ 548,331
	LESS:		
2	Arizona State Tax	Line 11	287
3	Interest Expense	Note (A) Line 21	544,215
4	Federal Taxable Income	Line 1 - Line 2 - Line 3	$ 3,829
5	Federal Tax Rate	Sch. WAR-1, Pg 2, Col. (D), L34	34.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 1,302
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 548,331
	LESS:		
8	Interest Expense	Note (A) Line 21	544,215
9	State Taxable Income	Line 7 - Line 8	$ 4,116
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 287
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 1,302
13	State Income Tax Expense	Line 11	287
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 1,589
15	Total Federal Income Tax Expense Per Company (Per Company Sch. C-1, L30)		(125,482)
16	Total State Income Tax Expense Per Company (Per Company Sch. C-1, L31)		(27,643)
17	RUCO Federal Income Tax Adjustment	Line 12 - Line 15	$ 126,784
18	RUCO State Income Tax Adjustment	Line 13 - Line 16	$ 27,929

NOTE (A):
Interest Synchronization:

19	Adjusted Rate Base (Sch. WAR-2, Col. (H), L17)	$	14,673,180
20	Weighted Cost of Debt (Sch. WAR-16 Col. (F), L1)		3.71%
21	Interest Expense (L18 X L19)	$	544,215

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Long-Term Debt	$ 75,000,000	50.76%	7.31%	3.71%
2	Common Equity	72,744,646	49.24%	8.33%	4.10%
3	Total Capitalization	$ 147,744,646	100.00%		
4	WEIGHTED AVERAGE COST OF CAPITAL				7.81%

References:
Columns (A) Thru (D): Testimony, WAR

ARIZONA WATER COMPNAY

W-01445A-08-0440

Pinewood System

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Pinewood System

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WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 1,882,836	$ 1,806,850
2	Adjusted Operating Income (Loss)	$ 104,677	$ 146,358
3	Current Rate of Return (L2 / L1)	5.56%	8.10%
4	Required Operating Income (L5 X L1)	$ 184,787	$ 141,086
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.81%
6	Operating Income Deficiency (L4 - L2)	$ 80,110	$ (5,272)
7	Gross Revenue Conversion Factor (WAR-1, Page 2)	1.6286	1.3703
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 130,470	$ (7,224)
9	Adjusted Test Year Revenue	$ 1,047,463	$ 1,046,390
10	Proposed Annual Revenue (L8 + L9)	$ 1,177,933	$ 1,039,166
11	Required Percentage Increase in Revenue (L8 / L9)	12.46%	-0.69%
12	Consolidated Revenue Adjustment (Sedona/Pinewood/Rimrock)	$ 6,107	$ -
13	Required Increase in Gross Revenue Under Company Proposed Consolidation	$ 136,993	$ -
14	Required Revenue Under Company Proposed Consolidation	$ 1,183,734	$ -
15	Required Percentage Increase in Revenue Under Company Proposed Consolidation	13.09%	-
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule WAR-2, WAR-7, and WAR-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.2702			
3	Subtotal (L1 - L2)	0.7298			
4	**Revenue Conversion Factor** (L1 / L3)	**1.3703**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	21.5564%			
9	Effective Federal Income Tax Rate (L7 X L8)	20.0544%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	27.0224%			
11	Required Operating Income (Sch. WAR-1, Pg 1, C (B), L4)	$ 141,086			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. WAR-1, Pg 1, C (B), L2)	146,358			
13	Required Increase In Operating Income (L11 - L12)		$ (5,272)		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 27,427			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	29,379			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ (1,952)		
17	Total Required Increase In Revenue (L13 + L16)		$ (7,224)		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. WAR-1, Pg 1, Col. (B), L12)			$ 1,039,166	
19	Operating Expense Excluding Income Tax (WAR-7, Col. (E), L27 - L22 - L23)			870,653	
20	Synchronized Interest (Col. (C), L37)			67,014	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 101,499	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 7,072
24	Fed. Taxable Income (L21 - L23)			$ 94,426	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ 6,250	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ 6,605	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ -	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 20,355
31	Combined Federal and State Income Tax (L23 + L30)				$ 27,427
32	Test Year Combined Income Tax, RUCO as Adjusted (WAR-7, Col. (C), L22 + L23)				$ 29,379
33	RUCO Adjustment (L31 - L32) (See WAR-6, Col. (D), L23)				$ (1,952)
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				21.56%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 1,806,850	
36	Weighted Avg. Cost of Debt (Sch. WAR-16, Col. (F), L1)			3.71%	
37	Synchronized Interest (L35 X L36)			$ 67,014	

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 863	$ -	$ 863
2	Source of Supply Plant	1,146,589	(13,512)	1,133,076
3	Pumping Plant	471,603	(40,464)	431,139
4	Water Treatment Plant	32,915	-	32,915
5	Transmission & Distribution Plant	3,563,550	(89)	3,563,461
6	General Plant	239,448	(3,542)	235,907
7	Total Gross Plant in Service	$ 5,454,969	$ (57,607)	$ 5,397,362
8	Accumulated Depreciation	(2,349,271)	12,479	(2,336,792)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 3,105,698	$ (45,128)	$ 3,060,570
10	Advances In Aid Of Const.	$ (249,075)	$ -	$ (249,075)
11	Contribution In Aid of Const.	$ (783,751)	$ -	$ (783,751)
12	Accumulated Amortization of CIAC	$ 296,411	-	296,411
13	NET CIAC (L5 + L6)	$ (487,340)	$ -	$ (487,340)
14	Deferred Income Tax	$ (565,368)	$ -	$ (565,368)
15	Allowance for Working Capital	$ 78,921	$ (30,858)	$ 48,063
16	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
17	Rounding	$ -	$ -	$ -
18	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 1,882,836	$ (75,986)	$ 1,806,850

References:
Column (A): Company Schedule B-1
Column (B): Schedule WAR-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Pinewood System
Schedule WAR-3

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2 REMOVE PTY PLANT	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4 REMOVE PTY PLANT	(F) ADJMT NO. 5	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 863	$ -	$ -	$ -	$ -	$ -	$ -	$ 863
2	Source of Supply Plant	1,146,589	-	-	(13,512)	-	-	-	1,133,076
3	Pumping Plant	471,603	-	-	-	(40,464)	-	-	431,139
4	Water Treatment Plant	32,915	-	-	-	-	-	-	32,915
5	Transmission & Distribution Plant	3,563,550	-	-	-	(89)	-	-	3,563,461
6	General Plant	239,448	-	(3,542)	-	-	-	-	235,907
7	Total Gross Plant in Service	$ 5,454,969	$ -	$ (3,542)	$ (13,512)	$ (40,553)	$ -	$ -	$ 5,397,362
8	Accumulated Depreciation	(2,349,271)	496	118	10,674	1,191	-	-	(2,336,792)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 3,105,698	$ 496	$ (3,424)	$ (2,838)	$ (39,362)	$ -	$ -	$ 3,060,570
10	Advances In Aid Of Const.	$ (249,075)	$ -	$ -	$ -	$ -	$ -	$ -	$ (249,075)
11	Contribution In Aid of Const.	$ (783,751)	$ -	$ -	$ -	$ -	$ -	$ -	$ (783,751)
12	Accumulated Amortization of CIAC	296,411	-	-	-	-	-	-	296,411
13	NET CIAC (L5 + L6)	$ (487,340)	$ -	$ -	$ -	$ -	$ -	$ -	$ (487,340)
14	Deferred Income Tax	$ (565,368)	$ -	$ -	$ -	$ -	$ -	$ -	$ (565,368)
15	Allowance for Working Capital	78,921	$ -	$ -	$ -	$ -	$ -	$ (30,858)	$ 48,063
16	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Rounding	$ -							$ -
18	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 1,882,836	$ 496	$ (3,424)	$ (2,838)	$ (39,362)	$ -	$ (30,858)	$ 1,806,850

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See WAR-4 Total, WAR-4 Direct, WAR-4 PHX OFF and WAR-4 MS Schedules and WAR Testi
Column (C): Adjustment No. 2 - To Remove Post Test Year Phoenix Office Plant and Accum. Depre.
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Remove Company PTY Plant Adjustment JMR-1
Column (F): Adjustment No. 5 - Intentionally Left Blank
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	(C) 12/31/1999 Per Decision No. 64282	(D) ADJ-1 Remove Post Test Year Plant	(E) Plant Balance 12/31/1999
1	301	Organization	0.00%	0.00%	-	$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111	-	-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111	-	-	-
4	310.1	Water Rights	0.00%	0.00%	2,215	-	2,215
5	310.3	Other Source of Supply Land	0.00%	0.00%	69,340	-	69,340
6	310.4	Wells - Other	See Acct. 111	See Acct. 111	-	-	-
7	314	Wells	2.59%	2.59%	993,976	-	993,976
8	320	Pumping Plant Land	0.00%	0.00%	95	-	95
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	29,870	-	29,870
10	325	Electric Pumping Equipment	2.59%	2.59%	240,210	-	240,210
11	328	Gas Engine Equipment	2.59%	2.59%	-	-	-
12	330	Water Treatment Plant Land	0.00%	0.00%	-	-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	7,060	-	7,060
14	332	Water Treatment Equipment	2.59%	2.59%	55,795	-	55,795
15	340	Transmission and Distribution Land	0.00%	0.00%	18,146	-	18,146
16	342	Storage Tanks	2.59%	2.59%	331,865	-	331,865
17	343	Transmission & Distribution Mains	2.59%	2.59%	1,757,450	-	1,757,450
18	344	Fire Sprinkler Taps	2.59%	2.59%	10,608	-	10,608
19	345	Services	2.59%	2.59%	641,270	-	641,270
20	346	Meters	2.59%	2.59%	133,287	-	133,287
21	348	Hydrants	2.59%	2.59%	111,924	-	111,924
22	389	General Plant Land	0.00%	0.00%	2,858	-	2,858
23	390	General Plant Structures	2.59%	2.59%	13,590	-	13,590
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	-	-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	130	-	130
26	393	Warehouse Equipment	2.59%	2.59%	-	-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	4,835	-	4,835
28	395	Laboratory Equipment	2.59%	2.59%	-	-	-
29	396	Power Operated Equipment	2.59%	2.59%	1,382	-	1,382
30	397	Communication Equipment	2.59%	2.59%	14,265	-	14,265
31	398	Miscellaneous Equipment	2.59%	2.59%	-	-	-
32		**TOTAL DIRECT WATER PLANT**			$ 4,440,171	$ -	$ 4,440,171
33		Post Test Year Plant (PTYP)			156,638	(156,638)	-
34		**RUCO Total Water Plant In Service**			$ 4,596,809	$ (156,638)	$ 4,440,171
35							
36		**Company Direct Plant As Filed**					
37							
38		**RUCO Direct Plant Adjustment**					
39							
40		Reserve Deficiency Accrual - Decision No. 38733					
41							
42		Net (Salvage)/Cost of Removal					
43		Accumulated Depreciation			(1,576,616)		$ (1,576,616)
44		Accumulated Depreciation - PTYP			(98,700)	98,700.00	-
45		RUCO Total Accumulated Depreciation - Calculated			$ (1,675,316)		$ (1,576,616)
46							
47		Company As Filed - Accumulated Depreciation			-	-	(1,576,616)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ (1,675,316)	$ -	$ -
49							
50		**RUCO Net Adjustment**					
51							
52							
53							

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other Intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2000 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2000
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	504			-	2,719
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	69,340
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	14,724			25,935	1,008,700
8	320	Pumping Plant Land	0.00%	0.00%				-	95
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	1,050			787	30,920
10	325	Electtric Pumping Equipment	2.59%	2.59%	99,292	(9,236)		7,388	330,266
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	616			191	7,676
14	332	Water Treatment Equipment	2.59%	2.59%	14,307	(9,500)		1,507	60,602
15	340	Transmission and Distribution Land	0.00%	0.00%				-	18,146
16	342	Storage Tanks	2.59%	2.59%				8,595	331,865
17	343	Transmission & Distribution Mains	2.59%	2.59%	22,330			45,807	1,779,780
18	344	Fire Sprinkler Taps	2.59%	2.59%				275	10,608
19	345	Services	2.59%	2.59%	5,812			16,684	647,082
20	346	Meters	2.59%	2.59%	3,594			3,499	136,881
21	348	Hydrants	2.59%	2.59%	87			2,900	112,011
22	389	General Plant Land	0.00%	0.00%				-	2,858
23	390	General Plant Structures	2.59%	2.59%				352	13,590
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	219			6	349
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	2,177			153	7,012
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				36	1,382
30	397	Communication Equipment	2.59%	2.59%	1,835			393	16,100
31	398	Miscellaneous Equipment	2.59%	2.59%				-	-
32		**TOTAL DIRECT WATER PLANT**			$ 166,548	$ (18,736)	$ -	$ 114,508	$ 4,587,983
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 166,548	$ (18,736)	$ -	$ 114,508	$ 4,587,983
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						232	
43		Accumulated Depreciation						(1,672,157)	$ (1,672,157)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(1,672,157)	$ (1,672,157)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(1,672,556)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (1,672,157)	$ 399
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2001 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2001
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	132			-	2,851
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	69,340
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	34,304			26,570	1,043,004
8	320	Pumping Plant Land	0.00%	0.00%				-	95
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	204			803	31,124
10	325	Electtric Pumping Equipment	2.59%	2.59%	45,781	(18,742)		8,904	357,305
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				199	7,676
14	332	Water Treatment Equipment	2.59%	2.59%	1,187			1,585	61,789
15	340	Transmission and Distribution Land	0.00%	0.00%				-	18,146
16	342	Storage Tanks	2.59%	2.59%	1,090			8,609	332,955
17	343	Transmission & Distribution Mains	2.59%	2.59%	96,971			47,352	1,876,751
18	344	Fire Sprinkler Taps	2.59%	2.59%				275	10,608
19	345	Services	2.59%	2.59%	5,778			16,834	652,860
20	346	Meters	2.59%	2.59%	4,125			3,599	141,006
21	348	Hydrants	2.59%	2.59%	4,636	(1,330)		2,944	115,317
22	389	General Plant Land	0.00%	0.00%				-	2,858
23	390	General Plant Structures	2.59%	2.59%				352	13,590
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%				9	349
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%				182	7,012
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%	3,090			76	4,472
30	397	Communication Equipment	2.59%	2.59%	888			429	16,989
31	398	Miscellaneous Equipment	2.59%	2.59%				-	-
32		**TOTAL DIRECT WATER PLANT**			$ 198,187	$ (20,072)	$ -	$ 118,721	$ 4,766,099
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 198,187	$ (20,072)	$ -	$ 118,721	$ 4,766,099
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						-	
43		Accumulated Depreciation						(1,770,806)	$ (1,770,806)
44		Accumulated Depreciation - PTYP						-	$ -
45		RUCO Total Accumulated Depreciation - Calculated						(1,770,806)	$ (1,770,806)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(1,771,348)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (1,770,806)	$ 542
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2002 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2002
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	2,378			-	5,229
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	69,340
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	1,436			27,032	1,044,441
8	320	Pumping Plant Land	0.00%	0.00%				-	95
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	8,612			918	39,736
10	325	Electtric Pumping Equipment	2.59%	2.59%	26,528	(23,155)		9,298	360,677
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				199	7,676
14	332	Water Treatment Equipment	2.59%	2.59%				1,600	61,789
15	340	Transmission and Distribution Land	0.00%	0.00%				-	18,146
16	342	Storage Tanks	2.59%	2.59%	173			8,626	333,128
17	343	Transmission & Distribution Mains	2.59%	2.59%	13,761			48,786	1,890,512
18	344	Fire Sprinkler Taps	2.59%	2.59%	5,715			349	16,323
19	345	Services	2.59%	2.59%	20,589	(572)		17,168	672,878
20	346	Meters	2.59%	2.59%		(141)		3,650	140,865
21	348	Hydrants	2.59%	2.59%	6,305	(1,459)		3,049	120,163
22	389	General Plant Land	0.00%	0.00%				-	2,858
23	390	General Plant Structures	2.59%	2.59%				352	13,590
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%				9	349
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	1,181			197	8,192
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				116	4,472
30	397	Communication Equipment	2.59%	2.59%				440	16,989
31	398	Miscellaneous Equipment	2.59%	2.59%				-	-
32		**TOTAL DIRECT WATER PLANT**			$ 86,678	$ (25,327)	$ -	$ 121,789	$ 4,827,450
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 86,678	$ (25,327)	$ -	$ 121,789	$ 4,827,450
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						(4)	
43		Accumulated Depreciation						(1,867,272)	$ (1,867,272)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(1,867,272)	(1,867,272)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(1,867,814)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (1,867,272)	$ 542
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other Intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2003 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2003
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	3,845			-	9,074
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	69,340
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				27,051	1,044,441
8	320	Pumping Plant Land	0.00%	0.00%				-	95
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	234			1,032	39,970
10	325	Electtric Pumping Equipment	2.59%	2.59%	19,828	(17,531)		9,371	362,974
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				199	7,676
14	332	Water Treatment Equipment	2.59%	2.59%	5,432	(6,955)		1,581	60,266
15	340	Transmission and Distribution Land	0.00%	0.00%				-	18,146
16	342	Storage Tanks	2.59%	2.59%				8,628	333,128
17	343	Transmission & Distribution Mains	2.59%	2.59%	14,254			49,149	1,904,766
18	344	Fire Sprinkler Taps	2.59%	2.59%				423	16,323
19	345	Services	2.59%	2.59%	10,049			17,558	682,927
20	346	Meters	2.59%	2.59%	326			3,653	141,191
21	348	Hydrants	2.59%	2.59%	4,031			3,164	124,194
22	389	General Plant Land	0.00%	0.00%				-	2,858
23	390	General Plant Structures	2.59%	2.59%				352	13,590
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%				9	349
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	3,319			255	11,511
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				116	4,472
30	397	Communication Equipment	2.59%	2.59%				440	16,989
31	398	Miscellaneous Equipment	2.59%	2.59%				-	-
32		**TOTAL DIRECT WATER PLANT**			$ 61,318	$ (24,486)	$ -	$ 122,980	$ 4,864,283
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 61,318	$ (24,486)	$ -	$ 122,980	$ 4,864,283
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						(7)	
43		Accumulated Depreciation						(1,965,774)	$ (1,965,774)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(1,965,774)	(1,965,774)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(1,966,315)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (1,965,774)	$ 541
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111	593			-	593
4	310.1	Water Rights	0.00%	0.00%	2,066			-	11,140
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	69,340
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				27,051	1,044,441
8	320	Pumping Plant Land	0.00%	0.00%				-	95
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				1,035	39,970
10	325	Electtric Pumping Equipment	2.59%	2.59%	81,100	(89,661)		9,290	354,413
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				199	7,676
14	332	Water Treatment Equipment	2.59%	2.59%	1,902	(36,990)		1,107	25,179
15	340	Transmission and Distribution Land	0.00%	0.00%				-	18,146
16	342	Storage Tanks	2.59%	2.59%				8,628	333,128
17	343	Transmission & Distribution Mains	2.59%	2.59%				49,333	1,904,766
18	344	Fire Sprinkler Taps	2.59%	2.59%				423	16,323
19	345	Services	2.59%	2.59%	11,071	(292)		17,827	693,706
20	346	Meters	2.59%	2.59%	6,833	(180)		3,743	147,844
21	348	Hydrants	2.59%	2.59%				3,217	124,194
22	389	General Plant Land	0.00%	0.00%				-	2,858
23	390	General Plant Structures	2.59%	2.59%				352	13,590
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	239			12	588
26	393	Warehouse Equipment	2.59%	2.59%	243			3	243
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	830			309	12,341
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				116	4,472
30	397	Communication Equipment	2.59%	2.59%	453			446	17,441
31	398	Miscellaneous Equipment	2.59%	2.59%				-	-
32		**TOTAL DIRECT WATER PLANT**			$ 105,330	$ (127,123)	$ -	$ 123,091	$ 4,842,489
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 105,330	$ (127,123)	$ -	$ 123,091	$ 4,842,489
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						(4)	
43		Accumulated Depreciation						(1,961,745)	$ (1,961,745)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(1,961,745)	(1,961,745)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(1,962,287)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (1,961,745)	$ 542
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	593
4	310.1	Water Rights	0.00%	0.00%	3,720			-	14,860
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	69,340
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				27,051	1,044,441
8	320	Pumping Plant Land	0.00%	0.00%				-	95
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				1,035	39,970
10	325	Electtric Pumping Equipment	2.59%	2.59%	3,213	(1,314)		9,204	356,312
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				199	7,676
14	332	Water Treatment Equipment	2.59%	2.59%				652	25,179
15	340	Transmission and Distribution Land	0.00%	0.00%				-	18,146
16	342	Storage Tanks	2.59%	2.59%				8,628	333,128
17	343	Transmission & Distribution Mains	2.59%	2.59%	69			49,334	1,904,836
18	344	Fire Sprinkler Taps	2.59%	2.59%				423	16,323
19	345	Services	2.59%	2.59%	12,285	(985)		18,113	705,005
20	346	Meters	2.59%	2.59%				3,829	147,844
21	348	Hydrants	2.59%	2.59%				3,217	124,194
22	389	General Plant Land	0.00%	0.00%				-	2,858
23	390	General Plant Structures	2.59%	2.59%				352	13,590
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	460			21	1,048
26	393	Warehouse Equipment	2.59%	2.59%	748			16	992
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	643			328	12,984
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				116	4,472
30	397	Communication Equipment	2.59%	2.59%				452	17,441
31	398	Miscellaneous Equipment	2.59%	2.59%				-	-
32		**TOTAL DIRECT WATER PLANT**			$ 21,138	$ (2,299)	$ -	$ 122,970	$ 4,861,328
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 21,138	$ (2,299)	$ -	$ 122,970	$ 4,861,328
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						-	
43		Accumulated Depreciation						(2,082,416)	$ (2,082,416)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(2,082,416)	(2,082,416)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,082,958)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,082,416)	$ 542
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	593
4	310.1	Water Rights	0.00%	0.00%	5,918			-	20,778
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	69,340
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	2,288			27,081	1,046,728
8	320	Pumping Plant Land	0.00%	0.00%				-	95
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				1,035	39,970
10	325	Electtrlc Pumping Equipment	2.59%	2.59%	13			9,229	356,325
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				199	7,676
14	332	Water Treatment Equipment	2.59%	2.59%				652	25,179
15	340	Transmission and Distribution Land	0.00%	0.00%				-	18,146
16	342	Storage Tanks	2.59%	2.59%				8,628	333,128
17	343	Transmission & Distribution Mains	2.59%	2.59%	159,062			51,395	2,063,898
18	344	Fire Sprinkler Taps	2.59%	2.59%				423	16,323
19	345	Services	2.59%	2.59%	22,444	(1,205)		18,535	726,244
20	346	Meters	2.59%	2.59%	1,928			3,854	149,773
21	348	Hydrants	2.59%	2.59%				3,217	124,194
22	389	General Plant Land	0.00%	0.00%				-	2,858
23	390	General Plant Structures	2.59%	2.59%				352	13,590
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%				27	1,048
26	393	Warehouse Equipment	2.59%	2.59%				26	992
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	656			345	13,640
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				116	4,472
30	397	Communication Equipment	2.59%	2.59%				452	17,441
31	398	Miscellaneous Equipment	2.59%	2.59%				-	-
32		**TOTAL DIRECT WATER PLANT**			$ 192,309	$ (1,205)	$ -	$ 125,564	$ 5,052,432
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 192,309	$ (1,205)	$ -	$ 125,564	$ 5,052,432
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						(11)	
43		Accumulated Depreciation						(2,206,785)	$ (2,206,785)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(2,206,785)	(2,206,785)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,207,327)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,206,785)	$ 542
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) Decision 64282 1/1/2002 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				30	593
4	310.1	Water Rights	0.00%	0.00%	9,739			-	30,517
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	69,340
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				27,110	1,046,728
8	320	Pumping Plant Land	0.00%	0.00%				-	95
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				1,035	39,970
10	325	Electtric Pumping Equipment	2.59%	2.59%	53,737	(18,988)		9,679	391,074
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				199	7,676
14	332	Water Treatment Equipment	2.59%	2.59%				652	25,179
15	340	Transmission and Distribution Land	0.00%	0.00%				-	18,146
16	342	Storage Tanks	2.59%	2.59%				8,628	333,128
17	343	Transmission & Distribution Mains	2.59%	2.59%	48,867	(381)		54,083	2,112,384
18	344	Fire Sprinkler Taps	2.59%	2.59%				423	16,323
19	345	Services	2.59%	2.59%	77,966	(1,795)		19,796	802,415
20	346	Meters	2.59%	2.59%	2,583			3,913	152,356
21	348	Hydrants	2.59%	2.59%	4,337			3,273	128,531
22	389	General Plant Land	0.00%	0.00%				-	2,858
23	390	General Plant Structures	2.59%	2.59%				352	13,590
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%		(220)		24	828
26	393	Warehouse Equipment	2.59%	2.59%				26	992
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	426			359	14,066
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				116	4,472
30	397	Communication Equipment	2.59%	2.59%				452	17,441
31	398	Miscellaneous Equipment	2.59%	2.59%				-	-
32		**TOTAL DIRECT WATER PLANT**			$ 197,656	$ (21,384)	$ -	$ 130,149	$ 5,228,704
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 197,656	$ (21,384)	$ -	$ 130,149	$ 5,228,704
35									
36		**Company Direct Plant As Filed**							5,228,703
37									
38		**RUCO Direct Plant Adjustment**							$ 1
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						-	
43		Accumulated Depreciation						(2,315,550)	$ (2,315,550)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(2,315,550)	(2,315,550)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(2,316,092)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (2,315,550)	$ 542
49									
50		**RUCO Net Adjustment**							$ 542
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
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Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2003 12/31/2003 Per Decision 68302	ADJ-1 Remove Post Test Year Plant	Balance 12/31/2003
1	301	Organization	0.00%	651		651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.	8,496		8,496
4	310.1	Water Rights	0.00%	-		-
5	310.3	Other Source of Supply Land	0.00%	-		-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
7	314	Wells	2.59%	-		-
8	320	Pumping Plant Land	0.00%	-		-
9	321	Pumping Plant Structures and Improvements	2.59%	-		-
10	325	Electric Pumping Equipment	2.59%	-		-
11	328	Gas Engine Equipment	2.59%	-		-
12	330	Water Treatment Plant Land	0.00%	-		-
13	331	Water Treatment Structures and Improvements	2.59%	-		-
14	332	Water Treatment Equipment	2.59%	-		-
15	340	Transmission and Distribution Land	0.00%	-		-
16	342	Storage Tanks	2.59%	-		-
17	343	Transmission and Distribution Mains	2.59%	-		-
18	344	Fire Sprinkler Taps	2.59%	-		-
19	345	Services	2.59%	-		-
20	346	Meters	2.59%	-		-
21	348	Hydrants	2.59%	-		-
22	389	General Plant Land	0.00%	-		-
23	390	General Plant Structures	2.59%	31,795		31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	1,267,373		1,267,373
25	391	Office Furniture and Equipment	2.59%	3,505,411		3,505,411
26	393	Warehouse Equipment	2.59%	3,705		3,705
27	394	Tools, Shop and Garage Equipment	2.59%	30,450		30,450
28	395	Laboratory Equipment	2.59%	977		977
29	396	Power Operated Equipment	2.59%	-		-
30	397	Communication Equipment	2.59%	143,052		143,052
31	398	Miscellaneous Equipment	2.59%	7,207		7,207
32		**TOTAL PHOENIX OFFICE PLANT**		4,999,117	-	4,999,117
33		Post Test Year Plant (PTYP)		-	-	-
34		**RUCO Total Phoenix Office**		4,999,117	-	4,999,117
35						
36		**Company Phoenix Office As Filed**		4,999,117		4,999,117
37						
38		RUCO Phoenix Office Plant Adjustment		-		-
39						
40		Reserve Deficiency Accrual - Dec. 38733		-		-
41						
42		Net (Salvage)/Cost of Removal				
43		Accumulated Depreciation		(503,775)	-	(503,775)
44		Accumulated Depreciation - PTYP		-	-	-
45		RUCO Total Accumulated Depreciation - Calculated		(503,775)	-	(503,775)
46						
47		Company As Filed - Accumulated Depreciation				(503,775)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**				-
49						
50		**RUCO Net Adjustment**				
51						
52						
53						
54						
55						

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	48,512			78,228	1,315,885
25	391	Office Furniture and Equipment	2.59%	129,135	(7,465)		92,366	3,627,081
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	24,820			1,110	55,270
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	6,465			3,789	149,517
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		208,932	(7,465)	-	176,624	5,200,584
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,200,584
35								
36		**Company Phoenix Office As Filed**						5,200,584
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(672,934)	(672,934)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(672,934)	(672,934)
46								
47		Company As Filed - Accumulated Depreciation						(672,934)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(0)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				89,580	1,315,885
25	391	Office Furniture and Equipment	2.59%	221,339			96,808	3,848,420
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	20,585			1,698	75,855
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	885			3,884	150,402
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		242,809	-	-	193,101	5,443,393
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,443,393
35								
36		**Company Phoenix Office As Filed**						5,443,393
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(866,035)	(866,035)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(866,035)	(866,035)
46								
47		Company As Filed - Accumulated Depreciation						(866,035)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other Intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				94,864	1,315,885
25	391	Office Furniture and Equipment	2.59%	369,071			104,454	4,217,491
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	59,519			2,735	135,374
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	1,741			3,918	152,143
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		430,332	-	-	207,102	5,873,725
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,873,725
35								
36		**Company Phoenix Office As Filed**						5,873,725
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(1,073,138)	(1,073,138)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(1,073,138)	(1,073,138)
46								
47		Company As Filed - Accumulated Depreciation						(1,073,137)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(1)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				425	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	10,463			959	42,258
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	93			86,708	1,315,978
25	391	Office Furniture and Equipment	2.59%	464,535	(243,714)		112,093	4,438,312
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	40,312			4,028	175,686
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	4,089			3,993	156,232
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		519,493	(243,714)	-	208,514	6,149,503
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						6,149,503
35								
36		**Company Phoenix Office As Filed**						6,149,503
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(1,037,938)	(1,037,938)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(1,037,938)	(1,037,938)
46								
47		Company As Filed - Accumulated Depreciation						(1,036,382)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(1,556)
49								
50		**RUCO Net Adjustment**						(1,556)
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2003 12/31/2003 Per Decision 68302	2003 ADJ-1 Remove Post Test Year Plant	2003 Balance 12/31/2003
1	301	Organization	0.00%	-		-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
4	310.1	Water Rights	0.00%	-		-
5	310.3	Other Source of Supply Land	0.00%	80		80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
7	314	Wells	2.59%	-		-
8	320	Pumping Plant Land	0.00%	-		-
9	321	Pumping Plant Structures and Improvements	2.59%	-		-
10	325	Electric Pumping Equipment	2.59%	-		-
11	328	Gas Engine Equipment	2.59%	-		-
12	330	Water Treatment Plant Land	0.00%	-		-
13	331	Water Treatment Structures and Improvements	2.59%	-		-
14	332	Water Treatment Equipment	2.59%	2,050		2,050
15	340	Transmission and Distribution Land	0.00%	-		-
16	342	Storage Tanks	2.59%	-		-
17	343	Transmission and Distribution Mains	2.59%	6,066		6,066
18	344	Fire Sprinkler Taps	2.59%	-		-
19	345	Services	2.59%	-		-
20	346	Meters	2.59%	-		-
21	348	Hydrants	2.59%	-		-
22	389	General Plant Land	0.00%	-		-
23	390	General Plant Structures	2.59%	37,472		37,472
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	-		-
25	391	Office Furniture and Equipment	2.59%	3,983		3,983
26	393	Warehouse Equipment	2.59%	1,088		1,088
27	394	Tools, Shop and Garage Equipment	2.59%	58,430		58,430
28	395	Laboratory Equipment	2.59%	2,981		2,981
29	396	Power Operated Equipment	2.59%	1,458		1,458
30	397	Communication Equipment	2.59%	-		-
31	398	Miscellaneous Equipment	2.59%	-		-
32		**TOTAL METER SHOP PLANT**		113,608	-	113,608
33		Post Test Year Plant (PTYP)		-	-	-
34		**RUCO Total Meter Shop**		113,608	-	113,608
35						
36		**Company Meter Shop As Filed**		113,608		113,608
37						
38		RUCO Meter Shop Plant Adjustment		-		-
39						
40		Reserve Deficiency Accrual - Dec. 38733				
41						
42		Net (Salvage)/Cost of Removal				
43		Accumulated Depreciation		(30,118)	-	(30,118)
44		Accumulated Depreciation - PTYP		-	-	-
45		RUCO Total Accumulated Depreciation - Calculated		(30,118)	-	(30,118)
46						
47		Company As Filed - Accumulated Depreciation				(30,118)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**				-
49						
50		**RUCO Net Adjustment**				
51						
52						
53						
54						
55						
56		Notes				
57		Acct. 302 - Franchises amortized over 25 years.				
58		Acct. 303 - Other intangibles amortized over 15 & 20 Years.				
59		Acct. 310.4 - Wells - Other amortized over 24 years.				
60		Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.				

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	12,809			1,136	50,281
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				-	-
25	391	Office Furniture and Equipment	2.59%	3,166			144	7,149
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	1,575			1,534	60,005
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		17,550	-	-	3,168	131,158
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						131,158
35								
36		**Company Meter Shop As Filed**						131,158
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733						
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(33,286)	(33,286)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(33,286)	(33,286)
46								
47		Company As Filed - Accumulated Depreciation						(33,286)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				1,302	50,281
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				-	-
25	391	Office Furniture and Equipment	2.59%	94			186	7,243
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	2,004			1,580	62,009
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		2,097	-	-	3,422	133,256
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						133,256
35								
36		**Company Meter Shop As Filed**						133,256
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(36,708)	(36,708)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(36,708)	(36,708)
46								
47		Company As Filed - Accumulated Depreciation						(36,708)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	2,571			1,336	52,852
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				-	-
25	391	Office Furniture and Equipment	2.59%	1,610			208	8,853
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	3,115			1,646	65,124
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		7,296	-	-	3,544	140,551
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						140,551
35								
36		**Company Meter Shop As Filed**						140,551
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(40,251)	(40,251)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(40,251)	(40,251)
46								
47		Company As Filed - Accumulated Depreciation						(40,251)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						(0)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				1,369	52,852
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.				-	-
25	391	Office Furniture and Equipment	2.59%	1,893			254	10,745
26	393	Warehouse Equipment	2.59%	1,089			42	2,177
27	394	Tools, Shop and Garage Equipment	2.59%	2,298			1,716	67,422
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		5,280	-	-	3,707	145,832
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						145,832
35								
36		**Company Meter Shop As Filed**						145,832
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(43,958)	(43,958)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(43,958)	(43,958)
46								
47		Company As Filed - Accumulated Depreciation						(43,959)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						1
49								
50		**RUCO Net Adjustment**						1
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

EXPLANATION OF RATE BASE ADJUSTMENT NO. 2
POST TEST-YEAR PLANT - PHOENIX OFFICE

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) COMPANY ADJUSTED TY PLANT	(B) POST TY ADDITIONS	(C) 3-FACTOR ALLOCATOR	(D) REMOVE PTY PLANT
1	301	Organization	$ 19	$ -	2.95%	$ -
2	302	Franchises	-	-	2.95%	-
3	303	Other Intangibles	844	-	2.95%	-
4	310.1	Water Rights	30,517	-	2.95%	-
5	310.3	Other Source of Supply Land	69,342	-	2.95%	-
6	310.4	Wells - Other	-	-	2.95%	-
7	314	Wells	1,046,728	-	2.95%	-
8	320	Pumping Plant Land	95	-	2.95%	-
9	321	Pumping Plant Structures & Imprm'ts	39,970	-	2.95%	-
10	325	Electtric Pumping Equipment	431,538	-	2.95%	-
11	328	Gas Engine Equipment	-	-	2.95%	-
12	330	Water Treatment Plant Land	-	-	2.95%	-
13	331	Water Treatment Structures & Imprm'ts	7,676	-	2.95%	-
14	332	Water Treatment Equipment	25,239	-	2.95%	-
15	340	Transmission and Distribution Land	18,146	-	2.95%	-
16	342	Storage Tanks	333,128	-	2.95%	-
17	343	Transmission & Distribution Mains	2,112,652	-	2.95%	-
18	344	Fire Sprinkler Taps	16,323	-	2.95%	-
19	345	Services	802,415	-	2.95%	-
20	346	Meters	152,356	-	2.95%	-
21	348	Hydrants	128,531	-	2.95%	-
22	389	General Plant Land	2,858	-	2.95%	-
23	390	General Plant Structures	16,396	-	2.95%	-
24	390.1	Leasehold Improvements	38,821	-	2.95%	-
25	391	Office Furniture & Equipment	132,075	120,057	2.95%	3,542
26	393	Warehouse Equipment	1,165	-	2.95%	-
27	394	Tools, Shop & Garage Equipment	21,238	-	2.95%	-
28	395	Laboratory Equipment	117	-	2.95%	-
29	396	Power Operated Equipment	4,515	-	2.95%	-
30	397	Communication Equipment	22,050	-	2.95%	-
31	398	Miscellaneous Equipment	213	-	2.95%	-
32						
33		**TOTAL PTY WATER PLANT**	$ 5,454,969	$ 120,057		$ 3,542
34		Company As Filed	$ 5,454,969	120,057		3,542
35		Difference	$ -	$ -		$ -
36						
37		RUCO PTY Plant Adjustment				$ (3,542)
38						
39		RUCO PTY Accumulated Depreciation Plant Adjustment				$ 118
40						
41						
42		References:				
43		Column (A): Company Schedules B-2				
44		Column (B): Post Test Year Phoenix Office Plant Allocation				
45		Column (C): 3-Factor Allocator				
46		Column (D): Adjustment				

EXPLANATION OF RATE BASE ADJUSTMENT NO. 6
ALLOWANCE FOR WORKING CAPITAL

LINE NO.	DESCRIPTION	(A) AMOUNT	(B) REFERENCE
1	Working Cash Requirement Per Company	$ 24,661	Company Schedule B-5, PG. 1
2	Working Cash Requirement Per RUCO	(6,197)	RUCO Schedule WAR-5, Page 2
3	Adjustment	$ (30,858)	Line 2 - Line 1
4	Material and Supplies Inventories Per Company	$ 23,241	Company Schedule B-5, PG. 1
5	Material and Supplies Inventories Per RUCO	23,241	Company Schedule B-5, PG. 1
6	Adjustment	$ -	Line 5 - Line 4
7	Required Bank Balances Per Company	$ 15,175	Company Schedule B-5, PG. 1
8	Required Bank Balances Per RUCO	15,175	Company Schedule B-5, PG. 1
9	Adjustment	$ -	Line 8 - Line 7
10	Prepayments & Special Deposits Per Company	$ 15,844	Company Schedule B-5, PG. 1
11	Prepayments & Special Deposits Per RUCO	15,844	Company Schedule B-5, PG. 1
12	Adjustment	$ -	Line 11 - Line 10
13	TOTAL ADJUSTMENT (See WAR-2, Column (K))	$ (30,858)	Sum of Lines 3, 6, 9 & 12

EXPLANATION OF RATE BASE ADJUSTMENT NO. 6 - CONT'D
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
	Operating Expenses					
1	Purchased Power	$ 84,846	$ -	$ 84,846	35.92	$ 3,047,668
2	Payroll	294,552	(8,931)	285,621	14.00	3,998,698
3	Purchased Water	-	-	-	-	-
4	Chemicals	345	-	345	20.43	7,047
5	Property & Liability Insurance	8,812	-	8,812	(45.27)	(398,919)
6	Workman's Compensation Insurance	4,405	-	4,405	(46.50)	(204,833)
7	Health Insurance	76,799	(38)	76,761	(8.92)	(684,711)
8	Other Operating & Maintenance Expenses	218,087	(4,917)	213,170	30.00	6,395,108
9	Federal Current Income Taxes	59,219	(38,864)	20,355	37.00	753,131
10	State Current Income Taxes	13,045	(5,973)	7,072	37.00	261,680
11	FICA Taxes	19,814	(1,420)	18,394	14.00	257,518
12	FUTA & SUTA Taxes	474	-	474	83.10	39,389
13	Property Taxes	41,350	(3,158)	38,192	212.00	8,096,780
14	Registration, Svc. Contracts, & Misc. Fees	16,774	-	16,774	(98.83)	(1,657,774)
15	Retirement Annuities (401k)	25,349	(725)	24,624	34.72	854,940
16	Subtotal	863,872	(64,025)	799,847		20,765,722
17	Synchronized Interest	$ 69,833	$ (2,819)	$ 67,014	91.25	$ 6,115,068
18	Cost of Equity	114,954	(114,954)	-	-	-
19	Subtotal	$ 184,787	$ (117,773)	$ 67,014		$ 6,115,068
20	Total	$ 1,048,659	$ (181,797)	$ 866,861		$ 26,880,790

21	Expense Lag	Line 17, Col. (E) / (C)	31.01
22	Revenue Lag	Company B-5 Schedules	28.40
23	Net Lag	Line 18 - Line 17	(2.61)
24	RUCO Adjusted Expenses	Col. (C), Line 16	$ 866,861
25	Cash Working Capital	Line 19 X Line 20 / 365 Days	(6,197)
26	Company As Filed	Co. Schedule B-6, Page 1	-
27	Difference	Line 21 - Line 22	$ (6,197)
28	ADJUSTMENT	Line 27	$ (6,197)

NOTE: Expense Lag Days Used in the Last Western Group Rate Case.

NOTE: RUCO reviewed several invoices from a number of companies with terms of net 30 days.

References:
Column (A): - Company Schedule B-5
Column (B): RUCO Operating Income Adjustments (See Schedule WAR-7)
Column (C): Column (A) + (B)
Column (D): - Company Schedule B-5
Column (E): Column (C) X Column (D)

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 1,015,253	$ (1,022)	$ 1,014,231	$ (11,926)	$ 1,002,305
2	Commercial	22,880	(49)	22,832	3,029	25,860
3	Industrial	507	0	507	83	590
4	Private Fire Service	179	-	179	721	900
5	Other Water Revenues	1,784	(2)	1,782	565	2,346
6	Total Water Revenues	$ 1,040,604	$ (1,073)	$ 1,039,531	$ (7,530)	$ 1,032,001
7	Miscellaneous	$ 6,859	$ -	$ 6,859	$ 306	$ 7,165
8	Total Operating Revenues	$ 1,047,463	$ (1,073)	$ 1,046,390	$ (7,224)	$ 1,039,166
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	3,239	-	3,239	-	3,239
11	Pumping Expenses:	-				
12	Purchased Power	84,846	-	84,846	-	84,846
13	Purchased Gas	-	-	-	-	-
14	Other	56,303	-	56,303	-	56,303
15	Water Treatment Expenses	33,840	-	33,840	-	33,840
16	Transmission & Distribution Expenses	173,376	-	173,376	-	173,376
17	Customer Accounting Expenses	133,433	-	133,433	-	133,433
18	Sales Expense	1,188	-	1,188	-	1,188
19	Administrative & General Expenses	243,746	(40,012)	203,734	-	203,734
20	Total Operations & Maintenance Expense	$ 729,970	$ (40,012)	$ 689,958	$ -	$ 689,958
21	Depreciation & Amortization Expenses	$ 132,206	$ (5,641)	$ 126,565	$ -	$ 126,565
	Taxes					
22	Federal Income Taxes	$ 17,950	$ 3,854	$ 21,804	$ (1,449)	$ 20,355
23	State Income Taxes	3,954	3,622	7,576	(503)	7,072
24	Property Taxes	41,350	(3,158)	38,193	-	38,193
25	Other	17,357	(1,420)	15,937	-	15,937
26	Total Taxes	$ 80,611	$ 2,898	$ 83,509	$ (1,952)	$ 81,557
27	Total Operating Expenses	$ 942,787	$ (42,755)	$ 900,032	$ (1,952)	$ 898,080
28	Operating Income	$ 104,677	$ 41,681	$ 146,358	$ (5,272)	$ 141,086

References:
Column (A): Company Schedule C-1
Column (B): WAR-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): WAR-1
Column (E): Column (C) + Column (D)

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 1,015,253	$ -	$ -	$ -	$ -	$ (1,022)	$ -	$ -	$ -	$ -	$ -	$ 1,014,231
2	Commercial	22,880	-	-	-	-	(49)	-	-	-	-	-	22,832
3	Industrial	507	-	-	-	-	0	-	-	-	-	-	507
4	Private Fire Service	179	-	-	-	-		-	-	-	-	-	179
5	Other Water Revenues	1,784	-	-	-	-	(2)	-	-	-	-	-	1,782
6	Total Water Revenues	$ 1,040,604	$ -	$ -	$ -	$ -	$ (1,073)	$ -	$ -	$ -	$ -	$ -	$ 1,039,531
7	Miscellaneous	$ 6,859	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,859
8	Total Operating Revenues	$ 1,047,463	$ -	$ -	$ -	$ -	$ (1,073)	$ -	$ -	$ -	$ -	$ -	$ 1,046,390
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	3,239	-	-	-	-	-	-	-	-	-	-	3,239
11	Pumping Expenses:												
12	Purchased Power	84,846	-	-	-	-	-	-	-	-	-	-	84,846
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	56,303	-	-	-	-	-	-	-	-	-	-	56,303
15	Water Treatment Expenses	33,840	-	-	-	-	-	-	-	-	-	-	33,840
16	Transmission & Distribution Expenses	173,376	-	-	-	-	-	-	-	-	-	-	173,376
17	Customer Accounting Expenses	133,433	-	-	-	-	-	-	-	-	-	-	133,433
18	Sales Expense	1,188	-	-	-	-	-	-	-	-	-	-	1,188
19	Administrative & General Expenses	243,746	(8,931)	-	(725)	(28,351)	-	(38)		-	(1,967)	-	203,734
20	Total Operations & Maintenance Expense	$ 729,970	$ (8,931)	$ -	$ (725)	$ (28,351)	$ -	$ (38)	$ -	$ -	$ (1,967)	$ -	$ 689,958
21	Depreciation & Amortization Expenses	$ 132,206	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,641)	$ -	$ -	$ -	$ 126,565
	Taxes												
22	Federal Income Taxes	$ 17,950	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,854	$ 21,804
23	State Income Taxes	3,954	-	-	-	-	-	-	-	-	-	3,622	7,576
24	Property Taxes	41,350	-	-	-	-	-	-	-	(3,158)	-	-	38,193
25	Other	17,357	-	(1,420)	-	-	-	-	-	-	-	-	15,937
26	Total Taxes	$ 80,611	$ -	$ (1,420)	$ -	$ -	$ -	$ -	$ -	$ (3,158)	$ -	$ 7,475	$ 83,509
27	Total Operating Expenses	$ 942,787	$ (8,931)	$ (1,420)	$ (725)	$ (28,351)	$ -	$ (38)	$ (5,641)	$ (3,158)	$ (1,967)	$ 7,475	$ 900,032
28	Operating Income	$ 104,677	$ 8,931	$ 1,420	$ 725	$ 28,351	$ (1,073)	$ 38	$ 5,641	$ 3,158	$ 1,967	$ (7,475)	$ 146,358

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule WAR-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule WAR-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule WAR-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule WAR-10
7 - Depreciation Expense	Testimony, WAR And Schedule WAR-11
8 - Property Tax Expense	Testimony, WAR And Schedule WAR-12
9 - Rate Case Expense	Testimony, WAR And Schedule WAR-13
10 - Income Tax	Testimony, WAR And Schedule WAR-14

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
PAYROLL EXPENSE

LINE NO.	DESCRIPTION		(A) PER RUCO DR 1.11.d
1	Normalize Over-Time Over 4 Years:		
2	2005 OT Hours		15,008.5
3	2006 OT Hours		18,080.0
4	2007 OT Hours		28,132.5
5	2008 OT Hours		17,530.0
6			
7	Total OT Hours for 2005 - 2008		78,751.0
8	Divided by 4 Years		4
9			
10	Normalized Level of OT Hours/Yr.		19,687.8
11			
12	OT Hours in Test Year		28,132.5
13			
14	Amount of Abnormal TY OT Hours		8,444.8
15			
16	Multiplied by Average OT Hrly. Rate	**See NOTE**	35.85
17			
18	Total Abnormal OT Dollars in TY		$ 302,744
19			
20	3-Factor Allocator Per District		2.95%
21			
22	RUCO Adjustment		$ (8,931)
23			
24			
25			
26			
27			

28	3-Factor Allocator By District:			
29	Superstition	24.94%	White Tank	2.37%
30	Bisbee	4.98%	Ajo	0.81%
31	Sierra Vista	2.58%	Coolidge	5.27%
32	San Manuel	1.68%	Lakeside	6.20%
33	Oracle	2.28%	Overgaard	3.99%
34	Winkelman	0.22%	Sedona	8.45%
35	Miami	4.98%	Pinewood	2.95%
36	Casa Grande	26.55%	Rimrock	1.48%
37	Stanfield	0.27%		
38				
39				
40				
41				
42	**Calculation Notes:**			
43	Average of Hourly Rate	$ 21.65		
44	OT Hourly Rate 1.5	32.48		

NOTE: The Company calculated the average hourly rate for overtime in response to data request All-11.6 to be $35.85. RUCO accepts that rate in making its payroll adjustments.

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PAYROLL TAX EXPENSE ASSOCIATED WITH RUCO ADJUSTMENT 1

LINE NO.	DESCRIPTION	(A) PER RUCO DR 1.11.d
1	Payroll Tax Expense:	
2		
3	Total Abnormal OT Dollars in TY	$ 302,744
4		
5	3-Factor Allocator Per District	2.95%
6		
7	RUCO Allocated Payroll by District	$ 8,931
8		
9	Payroll Tax Expense Allocator By Group:	
10		
11	RUCO Payroll Tax Expense Allocator by Group	15.90%
12		
13	RUCO Payroll Tax Expense Adjustment	$ (1,420)
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Payroll Tax Expense Allocator By Group:	
39	Eastern Group	7.47%
40	Western Group	11.65%
41	Northern Group	15.90%

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
PAYROLL 401(K) EXPENSE ASSOCIATED WITH RUCO ADJUSTMENT 1

LINE NO.	DESCRIPTION	(A) PER RUCO DR 1.11.d
1	Payroll 401(K) Expense:	
2		
3	Total Abnormal OT Dollars in TY	$ 302,744
4		
5	3-Factor Allocator Per District	2.95%
6		
7	RUCO Allocated Payroll by District	$ 8,931
8		
9	Payroll 401(K) Expense Allocator By Group:	
10		
11	RUCO Payroll 401(K) Expense Allocator by Group	8.12%
12		
13	RUCO Payroll 401(K) Expense Adjustment	$ (725)
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Payroll Tax Expense Allocator By Group:	
39	Eastern Group	8.39%
40	Western Group	8.45%
41	Northern Group	8.12%

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
INSURANCE EXPENSE

LINE NO.		(A) INCREASE/ (DECREASE) LONG-TERM DISABILITY PER COMPANY	(B) RUCO ADJUSTMENT	(C) INCREASE/ (DECREASE) LONG-TERM DISABILITY PER RUCO	
1	System				
2					
3	Eastern Group				
4	Supersition	$ 2,224	$ (273)	$ 1,950	
5	Apache Junction				
6	Superior				
7	Bisbee	122	(45)	77	
8	Sierra Vista	115	(38)	77	
9	San Manuel	5	(20)	(16)	
10	Oracle	25	(20)	5	
11	Saddlebrook	5	(0)	4	
12	Winkelman	0	(2)	(2)	
13	Miami	(338)	(40)	(378)	
14	Subtotal	$ 2,157	$ (439)	$ 1,718	
15					
16	Western Group				
17	Casa Grande	2,137	(298)	1,839	
18	Stanfield	20	(3)	17	
19	White Tank	148	(22)	126	
20	Ajo	58	(9)	49	
21	Coolidge	(127)	(62)	(189)	
22	Subtotal	$ 2,235	$ (393)	$ 1,842	
23					
24	Northern Group				
25	Lakeside	570	(65)	506	
26	Overgaard	507	(55)	452	
27	Sedona	445	(84)	361	
28	Pinewood	199	(38)	162	
29	Rimrock	87	(16)	71	
30	Subtotal	$ 1,809	$ (257)	$ 1,551	
31					
32					
33	Total Company	$ 6,201	$ (1,090)	$ 5,111	(a)

REFERENCE

COLUMN (A): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD
COLUMN (B): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD
COLUMN (C): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD

NOTES:

(a) CALCULATED AS FOLLOWS:		PER COMPANY	RUCO ADJUSTMENT	PER RUCO	REFERENCE
1	Current Rate per Payroll Dollar	$ 0.0036		$ 0.0036	COMPANY WORKPAPER - "GROUP INSURANCE" TAB LTD
2	Pro Forma Payroll Dollars	$ 11,095,569	$ 302,744	$ 10,792,825	COMPANY WORKPAPER - "GROUP INSURANCE)
3	Pro Forma LTD - Total Company	$ 39,944		$ 38,854	LINE 1 x LINE 2
4	Y/E Number of Customers	$ 83,825		$ 83,825	COMPANY WORKPAPER - "GROUP INSURANCE)
5	Pro Forma 2007 LTD - Spread	$ 38,854		$ 38,854	COMPANY WORKPAPER - "GROUP INSURANCE)
6	Increase / (Decrease)	$ 6,201		$ 5,111	COMPANY WORKPAPER - "GROUP INSURANCE)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 7
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCOUNT NO.	ACCOUNT NAME	(A) RUCO PLANT VALUE	(B) COMPANY PROPOSED DEP. RATES	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization	$ 19	0.00%	$ -
2	302	Franchises	-	See Acct. 111	-
3	303	Other Intangibles	844	See Acct. 111	-
4	310.1	Water Rights	30,517	0.00%	-
5	310.3	Other Source of Supply Land	69,342	0.00%	-
6	310.4	Wells - Other	-	See Acct. 111	-
7	314	Wells	1,033,216	3.13%	32,340
8	320	Pumping Plant Land	95	0.00%	-
9	321	Pumping Plant Structures & Imprm'ts	39,970	2.86%	1,143
10	325	Electtric Pumping Equipment	391,074	5.88%	22,995
11	328	Gas Engine Equipment	-	4.00%	-
12	330	Water Treatment Plant Land	-	0.00%	-
13	331	Water Treatment Structures & Imprm'ts	7,676	2.50%	192
14	332	Water Treatment Equipment	25,239	2.86%	722
15	340	Transmission and Distribution Land	18,146	0.00%	-
16	342	Storage Tanks	333,128	2.00%	6,663
17	343	Transmission & Distribution Mains	2,112,563	1.79%	37,815
18	344	Fire Sprinkler Taps	16,323	2.00%	326
19	345	Services	802,415	2.38%	19,097
20	346	Meters	152,356	4.55%	6,932
21	348	Hydrants	128,531	1.82%	2,339
22	389	General Plant Land	2,858	0.00%	-
23	390	General Plant Structures	16,396	2.50%	410
24	390.1	Leasehold Improvements	38,821	See Acct. 108.2	-
25	391	Office Furniture & Equipment	128,533	6.67%	8,573
26	393	Warehouse Equipment	1,165	5.00%	58
27	394	Tools, Shop & Garage Equipment	21,238	4.00%	850
28	395	Laboratory Equipment	117	5.00%	6
29	396	Power Operated Equipment	4,515	6.67%	301
30	397	Communication Equipment	22,050	6.67%	1,471
31	398	Miscellaneous Equipment	213	3.33%	7
32		Rounding	-		
33		TEST YEAR GROSS PLANT AND DEPRECIATION EXPENSE	$ 5,397,362		$ 142,240
34					
35		AMORTIZATION OF CONTRIBUTIONS	(783,751)	2.00%	(15,675)
36		Rounding			-
37	**TOTAL DEPRECIATION EXPENSE**				$ 126,565
38					
39	Company As Filed				132,206
40	Difference				$ (5,641)
41					
42	RUCO Adjustment (See WAR-8, Column (B))				$ (5,641)
43					
44					
45	3-Factor Allocator By District:				
46	Superstition	24.94%	White Tank	2.37%	
47	Bisbee	4.98%	Ajo	0.81%	
48	Sierra Vista	2.58%	Coolidge	5.27%	
49	San Manuel	1.68%	Lakeside	6.20%	
50	Oracle	2.28%	Overgaard	3.99%	
51	Winkelman	0.22%	Sedona	8.45%	
52	Miami	4.98%	Pinewood	2.95%	
	Casa Grande	26.55%	Rimrock	1.48%	
	Stanfield	0.27%			

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 8
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A)	(B)
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. WAR-7, Col (C), Ln 8	$ 1,046,390	
2	Adjusted Revenues In Year Ended December 2007	Sch. WAR-7, Col (C), Ln 8	1,046,390	
3	Proposed Revenues	Sch. WAR-7, Col (E), Ln 8	1,039,166	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 3,131,945	
5	Average Annual Operating Revenues	Line 4 / 3	1,043,982	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 2,087,964
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Company Schedule E	$ 74,403	
8	10% Of CWIP	Line 7 X 10%		$ 7,440
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	Company Workpapers	$ -	
10	Acc. Dep. Of Transportation Equipment	Company Workpapers	-	
11	Net Book Value Of Transportation Equipment	Line 9 + Line 10		$ (35,406)
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 2,059,998
	Calculation Of The Company's Tax Liability:			
	MULTIPLY:			
	FCV X Valuation Assessment Ratio X Property Tax Rates:			
13	Assessment Ratio	House Bill 2779	22.5%	
14	Assessed Value	Line 12 X Line 13	$ 463,500	
	Property Tax Rates:			
15	Primary Tax Rate	Company Workpapers	8.24%	
16	Secondary Tax Rate	Company Workpapers	0.00%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	8.24%	
	Property Tax			$ 38,192
	Tax On Parcel			-
18	Company's Total Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 38,192
19	Test Year Adjusted Property Tax Expense As Filed	Co. Sch. C-1		41,350
20	Decrease In Property Tax Expense	Line 18 - Line 19		$ (3,158)
21	RUCO Adjustment (See WAR-8, Column (C))	Line 20		$ (3,158)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 9
RATE CASE EXPENSE

LINE NO.	DESCRIPTION	(A) COMPANY ESTIMATE	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total	$ 500,000	$ (200,000)	$ 300,000
2	Allocation Factor			2.95%
3	Pinewood System (Line 1 X Line 2)			$ 8,850
4	Amortization Period - 3 Years			3
5	RUCO Adjusted Rate Case Expense (Line 3 / 3 Years)			$ 2,950
6	Company Rate Case Expenses As Filed (Company Sch. C-2)			$ 4,917
7	RUCO Pro Forma Rate Case Expense (Lines 5 - 6)			$ (1,967)
8	RUCO Adjustment (Line 7) (See WAR-8, Column (E))			$ (1,967)

3-Factor Allocator By District:

Superstition	24.94%	White Tank	2.37%
Bisbee	4.98%	Ajo	0.81%
Sierra Vista	2.58%	Coolidge	5.27%
San Manuel	1.68%	Lakeside	6.20%
Oracle	2.28%	Overgaard	3.99%
Winkelman	0.22%	Sedona	8.45%
Miami	4.98%	Pinewood	2.95%
Casa Grande	26.55%	Rimrock	1.48%
Stanfield	0.27%		

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 10
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. WAR-7, Column (C), L28 + L22 + L23	$ 175,737
	LESS:		
2	Arizona State Tax	Line 11	7,576
3	Interest Expense	Note (A) Line 21	67,014
4	Federal Taxable Income	Line 1 - Line 2 - Line 3	$ 101,147
5	Federal Tax Rate	Sch. WAR-1, Pg 2, Col. (D), L34	21.56%
6	Federal Income Tax Expense	Line 4 X line 5	$ 21,804
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 175,737
	LESS:		
8	Interest Expense	Note (A) Line 21	67,014
9	State Taxable Income	Line 7 - Line 8	$ 108,723
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 7,576
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 21,804
13	State Income Tax Expense	Line 11	7,576
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 29,379
15	Total Federal Income Tax Expense Per Company (Per Company Sch. C-1, L30)		17,950
16	Total State Income Tax Expense Per Company (Per Company Sch. C-1, L31)		3,954
17	RUCO Federal Income Tax Adjustment	Line 12 - Line 15	$ 3,854
18	RUCO State Income Tax Adjustment	Line 13 - Line 16	$ 3,622

NOTE (A):
Interest Synchronization:

19	Adjusted Rate Base (Sch. WAR-2, Col. (H), L17)	$ 1,806,850
20	Weighted Cost Of Debt (Sch. WAR-16 Col. (F), L1)	3.71%
21	Interest Expense (L18 X L19)	$ 67,014

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Long-Term Debt	$ 75,000,000	50.76%	7.31%	3.71%
2	Common Equity	72,744,646	49.24%	8.33%	4.10%
3	Total Capitalization	$ 147,744,646	100.00%		
4	WEIGHTED AVERAGE COST OF CAPITAL				7.81%

References:
Columns (A) Thru (D): Testimony, WAR

ARIZONA WATER COMPNAY

W-01445A-08-0440

Rimrock System

Arizona Water Company
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Rimrock System

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WAR-4 PHOENIX OFFICE	1 TO 5	RATE BASE ADJUSTMENT NO. 1 - PLANT & ACCUMULATED DEPRECIATION RECONCILIATION ADJUSTMENT
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WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 2,338,005	$ 2,293,279
2	Adjusted Operating Income (Loss)	$ (75,247)	$ (73,924)
3	Current Rate of Return (L2 / L1)	-3.22%	-3.22%
4	Required Operating Income (L5 X L1)	$ 229,458	$ 179,068
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.81%
6	Operating Income Deficiency (L4 - L2)	$ 304,705	$ 252,992
7	Gross Revenue Conversion Factor (WAR-1, Page 2)	1.6286	1.4482
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 496,253	$ 366,377
9	Adjusted Test Year Revenue	$ 507,981	$ 507,512
10	Proposed Annual Revenue (L8 + L9)	$ 1,004,234	$ 873,888
11	Required Percentage Increase in Revenue (L8 / L9)	97.69%	72.19%
12	Consolidated Revenue Adjustment (Sedona/Pinewood/Rimrock)	$ (222,992)	$ -
13	Required Increase in Gross Revenue Under Company Proposed Consolidation	$ 273,068	$ -
14	Required Revenue Under Company Proposed Consolidation	$ 780,936	$ -
15	Required Percentage Increase in Revenue Under Company Proposed Consolidation	53.77%	-
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule WAR-2, WAR-7, and WAR-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3095			
3	Subtotal (L1 - L2)	0.6905			
4	**Revenue Conversion Factor** (L1 / L3)	**1.4482**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	25.7756%			
9	Effective Federal Income Tax Rate (L7 X L8)	23.9795%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	30.9475%			
11	Required Operating Income (Sch. WAR-1, Pg 1, C (B), L4)	$ 179,068			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. WAR-1, Pg 1, C (B), L2)	(73,924)			
13	Required Increase In Operating Income (L11 - L12)		$ 252,992		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 42,134			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	(71,251)			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 113,384		
17	Total Required Increase In Revenue (L13 + L16)		$ 366,377		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. WAR-1, Pg 1, Col. (B), L12)			$ 873,888	
19	Operating Expense Excluding Income Tax (WAR-7, Col. (E), L27 - L22 - L23)			652,687	
20	Synchronized Interest (Col. (C), L37)			85,056	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 136,146	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 9,487
24	Fed. Taxable Income (L21 - L23)			$ 126,659	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ 6,250	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ 8,500	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ 10,397	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ -	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 32,647
31	Combined Federal and State Income Tax (L23 + L30)				$ 42,134
32	Test Year Combined Income Tax, RUCO as Adjusted (WAR-7, Col. (C), L22 + L23)				$ (71,251)
33	RUCO Adjustment (L31 - L32) (See WAR-6, Col. (D), L23)				$ 113,384
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				25.78%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 2,293,279	
36	Weighted Avg. Cost of Debt (Sch. WAR-16, Col. (F), L1)			3.71%	
37	Synchronized Interest (L35 X L36)			$ 85,056	

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Rimrock System
Schedule WAR-2
Page 1 of 1

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 401	$ -	$ 401
2	Source of Supply Plant	597,457	(62,097)	535,360
3	Pumping Plant	419,745	-	419,745
4	Water Treatment Plant	372,768	-	372,768
5	Transmission & Distribution Plant	3,355,961	-	3,355,961
6	General Plant	196,495	(1,777)	194,719
7	Total Gross Plant in Service	$ 4,942,827	$ (63,874)	$ 4,878,954
8	Accumulated Depreciation	(1,104,418)	60,858	(1,043,560)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 3,838,409	$ (3,015)	$ 3,835,394
10	Advances In Aid Of Const.	$ (1,080,835)	$ -	$ (1,080,835)
11	Contribution In Aid of Const.	$ (260,411)	$ -	$ (260,411)
12	Accumulated Amortization of CIAC	69,153	-	69,153
13	NET CIAC (L5 + L6)	$ (191,258)	$ -	$ (191,258)
14	Deferred Income Tax	$ (283,642)	$ -	$ (283,642)
15	Allowance for Working Capital	$ 55,331	$ (41,710)	$ 13,620
16	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
17	Rounding	$ -	$ -	$ -
18	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 2,338,005	$ (44,726)	$ 2,293,279

References:
Column (A): Company Schedule B-1
Column (B): Schedule WAR-3
Column (C): Column (A) + Column (B)

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Test Year Ended December 31, 2007

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2 REMOVE PTY PLANT	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 401	$ -	$ -	$ -	$ -	$ -	$ -	$ 401
2	Source of Supply Plant	597,457	-	-	(62,097)	-	-	-	535,360
3	Pumping Plant	419,745	-	-	-	-	-	-	419,745
4	Water Treatment Plant	372,768	-	-	-	-	-	-	372,768
5	Transmission & Distribution Plant	3,355,961	-	-	-	-	-	-	3,355,961
6	General Plant	196,495	-	(1,777)	-	-	-	-	194,719
7	Total Gross Plant in Service	$ 4,942,827	$ -	$ (1,777)	$ (62,097)	$ -	$ -	$ -	$ 4,878,954
8	Accumulated Depreciation	(1,104,418)	487	59	60,312	-	-	-	(1,043,560)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 3,838,409	$ 487	$ (1,718)	$ (1,785)	$ -	$ -	$ -	$ 3,835,394
10	Advances In Aid Of Const.	$ (1,080,835)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,080,835)
11	Contribution In Aid of Const.	$ (260,411)	$ -	$ -	$ -	$ -	$ -	$ -	$ (260,411)
12	Accumulated Amortization of CIAC	69,153	-	-	-	-	-	-	69,153
13	NET CIAC (L5 + L6)	$ (191,258)	$ -	$ -	$ -	$ -	$ -	$ -	$ (191,258)
14	Deferred Income Tax	$ (283,642)	$ -	$ -	$ -	$ -	$ -	$ -	$ (283,642)
15	Allowance for Working Capital	55,331	$ -	$ -	$ -	$ -	$ -	$ (41,710)	$ 13,620
16	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Rounding	$ -							$ -
18	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 2,338,005	$ 487	$ (1,718)	$ (1,785)	$ -	$ -	$ (41,710)	$ 2,293,279

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See WAR-4 Total, WAR-4 Direct, WAR-4 PHX OFF and WAR-4 MS Schedules and WAR Testimc
Column (C): Adjustment No. 2 - To Remove Post Test Year Phoenix Office Plant and Accum. Depre.
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Intentionally Left Blank
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) Decision 64282 1/1/2002 To Present	(C) 12/31/1999 Per Decision No. 64282	(D) ADJ-1 Remove Post Test Year Plant	(E) Plant Balance 12/31/1999
1	301	Organization	0.00%	0.00%	-	$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111	-	-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111	-	-	-
4	310.1	Water Rights	0.00%	0.00%	1,082	-	1,082
5	310.3	Other Source of Supply Land	0.00%	0.00%	13,010	-	13,010
6	310.4	Wells - Other	See Acct. 111	See Acct. 111	-	-	-
7	314	Wells	2.59%	2.59%	47,994	-	47,994
8	320	Pumping Plant Land	0.00%	0.00%	1,644	-	1,644
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%	4,633	-	4,633
10	325	Electtric Pumping Equipment	2.59%	2.59%	123,630	-	123,630
11	328	Gas Engine Equipment	2.59%	2.59%	-	-	-
12	330	Water Treatment Plant Land	0.00%	0.00%	-	-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	13,292	-	13,292
14	332	Water Treatment Equipment	2.59%	2.59%	33,144	-	33,144
15	340	Transmission and Distribution Land	0.00%	0.00%	3,431	-	3,431
16	342	Storage Tanks	2.59%	2.59%	206,513	-	206,513
17	343	Transmission & Distribution Mains	2.59%	2.59%	922,973	-	922,973
18	344	Fire Sprinkler Taps	2.59%	2.59%	-	-	-
19	345	Services	2.59%	2.59%	264,975	-	264,975
20	346	Meters	2.59%	2.59%	50,945	-	50,945
21	348	Hydrants	2.59%	2.59%	16,132	-	16,132
22	389	General Plant Land	0.00%	0.00%	-	-	-
23	390	General Plant Structures	2.59%	2.59%	1,408	-	1,408
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2	-	-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	-	-	-
26	393	Warehouse Equipment	2.59%	2.59%	-	-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	5,063	-	5,063
28	395	Laboratory Equipment	2.59%	2.59%	-	-	-
29	396	Power Operated Equipment	2.59%	2.59%	2,148	-	2,148
30	397	Communication Equipment	2.59%	2.59%	14,892	-	14,892
31	398	Miscellaneous Equipment	2.59%	2.59%	335	-	335
32		**TOTAL DIRECT WATER PLANT**			$ 1,727,244	$ -	$ 1,727,244
33		Post Test Year Plant (PTYP)			165,793	(165,793)	-
34		**RUCO Total Water Plant In Service**			$ 1,893,037	$ (165,793)	$ 1,727,244
35							
36		**Company Direct Plant As Filed**					
37							
38		**RUCO Direct Plant Adjustment**					
39							
40		Reserve Deficiency Accrual - Decision No. 38733					
41							
42		Net (Salvage)/Cost of Removal					
43		Accumulated Depreciation			(578,350)		$ (578,350)
44		Accumulated Depreciation - PTYP			(43,603)	43,603.00	-
45		RUCO Total Accumulated Depreciation - Caiculated			$ (621,953)		$ (578,350)
46							
47		Company As Filed - Accumulated Depreciation			-	-	(578,350)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ (621,953)	$ -	$ -
49							
50		**RUCO Net Adjustment**					
51							
52							
53							

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 68849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2000 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2000
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	251			-	1,333
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	13,010
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	3,964	(1,072)		1,281	50,887
8	320	Pumping Plant Land	0.00%	0.00%				-	1,644
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				120	4,633
10	325	Electtric Pumping Equipment	2.59%	2.59%	243			3,205	123,873
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				344	13,292
14	332	Water Treatment Equipment	2.59%	2.59%	3,681	(9,500)		783	27,325
15	340	Transmission and Distribution Land	0.00%	0.00%				-	3,431
16	342	Storage Tanks	2.59%	2.59%				5,349	206,513
17	343	Transmission & Distribution Mains	2.59%	2.59%	105,182	(1,492)		25,248	1,026,663
18	344	Fire Sprinkler Taps	2.59%	2.59%				-	-
19	345	Services	2.59%	2.59%	28,334	(698)		7,221	292,611
20	346	Meters	2.59%	2.59%		(914)		1,308	50,031
21	348	Hydrants	2.59%	2.59%	128			419	16,260
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%	45,882			631	47,290
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%				-	-
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%				131	5,063
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				56	2,148
30	397	Communication Equipment	2.59%	2.59%				386	14,892
31	398	Miscellaneous Equipment	2.59%	2.59%				9	335
32		**TOTAL DIRECT WATER PLANT**			$ 187,666	$ (13,676)	$ -	$ 46,489	$ 1,901,233
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 187,666	$ (13,676)	$ -	$ 46,489	$ 1,901,233
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						84	
43		Accumulated Depreciation						(611,079)	$ (611,079)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(611,079)	$ (611,079)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(611,231)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (611,079)	$ 152
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2001 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2001
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	69			-	1,402
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	13,010
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	113			1,319	51,000
8	320	Pumping Plant Land	0.00%	0.00%				-	1,644
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				120	4,633
10	325	Electtric Pumping Equipment	2.59%	2.59%	23,314	(9,745)		3,384	137,442
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				344	13,292
14	332	Water Treatment Equipment	2.59%	2.59%	7,802			809	35,126
15	340	Transmission and Distribution Land	0.00%	0.00%				-	3,431
16	342	Storage Tanks	2.59%	2.59%				5,349	206,513
17	343	Transmission & Distribution Mains	2.59%	2.59%	215,164	(1,437)		29,358	1,240,390
18	344	Fire Sprinkler Taps	2.59%	2.59%				-	-
19	345	Services	2.59%	2.59%	29,794	(3,782)		7,915	318,623
20	346	Meters	2.59%	2.59%	2,492	(663)		1,319	51,859
21	348	Hydrants	2.59%	2.59%	6,066			500	22,326
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				1,225	47,290
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%				-	-
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	984			144	6,047
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				56	2,148
30	397	Communication Equipment	2.59%	2.59%	1,710			408	16,602
31	398	Miscellaneous Equipment	2.59%	2.59%				9	335
32		**TOTAL DIRECT WATER PLANT**			$ 287,508	$ (15,627)	$ -	$ 52,259	$ 2,173,114
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 287,508	$ (15,627)	$ -	$ 52,259	$ 2,173,114
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						147	
43		Accumulated Depreciation						(647,563)	$ (647,563)
44		Accumulated Depreciation - PTYP						-	$ -
45		RUCO Total Accumulated Depreciation - Calculated						(647,563)	$ (647,563)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(648,073)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (647,563)	$ 510
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other Intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2002 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2002
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	967			-	2,369
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	13,010
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				1,321	51,000
8	320	Pumping Plant Land	0.00%	0.00%				-	1,644
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				120	4,633
10	325	Electtric Pumping Equipment	2.59%	2.59%	7,865			3,662	145,307
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				344	13,292
14	332	Water Treatment Equipment	2.59%	2.59%	887	(922)		909	35,092
15	340	Transmission and Distribution Land	0.00%	0.00%				-	3,431
16	342	Storage Tanks	2.59%	2.59%	237			5,352	206,750
17	343	Transmission & Distribution Mains	2.59%	2.59%	18,576	(1,384)		32,349	1,257,582
18	344	Fire Sprinkler Taps	2.59%	2.59%				-	-
19	345	Services	2.59%	2.59%	14,703	(199)		8,440	333,127
20	346	Meters	2.59%	2.59%	2,993	(380)		1,377	54,473
21	348	Hydrants	2.59%	2.59%				578	22,326
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				1,225	47,290
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%				-	-
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	976			169	7,024
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%	4,338			112	6,486
30	397	Communication Equipment	2.59%	2.59%				430	16,602
31	398	Miscellaneous Equipment	2.59%	2.59%	287			12	622
32		**TOTAL DIRECT WATER PLANT**			$ 51,831	$ (2,885)	$ -	$ 56,400	$ 2,222,060
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 51,831	$ (2,885)	$ -	$ 56,400	$ 2,222,060
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						(96)	
43		Accumulated Depreciation						(701,174)	$ (701,174)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(701,174)	(701,174)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(701,684)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (701,174)	$ 510
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2003 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2003
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	-
4	310.1	Water Rights	0.00%	0.00%	1,557			-	3,926
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	13,010
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	518,446			8,035	569,446
8	320	Pumping Plant Land	0.00%	0.00%				-	1,644
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				120	4,633
10	325	Electtric Pumping Equipment	2.59%	2.59%	219,991	(23,980)		6,302	341,319
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	10,733			483	24,025
14	332	Water Treatment Equipment	2.59%	2.59%	9,483			1,032	44,575
15	340	Transmission and Distribution Land	0.00%	0.00%				-	3,431
16	342	Storage Tanks	2.59%	2.59%				5,355	206,750
17	343	Transmission & Distribution Mains	2.59%	2.59%	9,552			32,695	1,267,134
18	344	Fire Sprinkler Taps	2.59%	2.59%	65			1	65
19	345	Services	2.59%	2.59%	24,843	(152)		8,948	357,818
20	346	Meters	2.59%	2.59%		(578)		1,403	53,895
21	348	Hydrants	2.59%	2.59%				578	22,326
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				1,225	47,290
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%	410			5	410
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	3,409			226	10,433
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				168	6,486
30	397	Communication Equipment	2.59%	2.59%	16,853			648	33,456
31	398	Miscellaneous Equipment	2.59%	2.59%				16	622
32		**TOTAL DIRECT WATER PLANT**			$ 815,342	$ (24,710)	$ -	$ 67,240	$ 3,012,692
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 815,342	$ (24,710)	$ -	$ 67,240	$ 3,012,692
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						(111)	
43		Accumulated Depreciation						(743,815)	$ (743,815)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(743,815)	(743,815)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(744,325)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (743,815)	$ 510
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111	266			-	266
4	310.1	Water Rights	0.00%	0.00%	926			-	4,852
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	13,010
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				14,749	569,446
8	320	Pumping Plant Land	0.00%	0.00%				-	1,644
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				120	4,633
10	325	Electtric Pumping Equipment	2.59%	2.59%				8,840	341,319
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	3,517			668	27,541
14	332	Water Treatment Equipment	2.59%	2.59%	26,035			1,492	70,610
15	340	Transmission and Distribution Land	0.00%	0.00%				-	3,431
16	342	Storage Tanks	2.59%	2.59%				5,355	206,750
17	343	Transmission & Distribution Mains	2.59%	2.59%	21,774	(632)		33,093	1,288,276
18	344	Fire Sprinkler Taps	2.59%	2.59%	5,939			79	6,004
19	345	Services	2.59%	2.59%	48,195			9,892	406,013
20	346	Meters	2.59%	2.59%	1,440	(164)		1,412	55,171
21	348	Hydrants	2.59%	2.59%	2,311			608	24,637
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				1,225	47,290
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%				11	410
26	393	Warehouse Equipment	2.59%	2.59%				-	-
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	256			274	10,688
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				168	6,486
30	397	Communication Equipment	2.59%	2.59%	750			876	34,206
31	398	Miscellaneous Equipment	2.59%	2.59%				16	622
32		**TOTAL DIRECT WATER PLANT**			$ 111,409	$ (796)	$ -	$ 78,876	$ 3,123,306
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 111,409	$ (796)	$ -	$ 78,876	$ 3,123,306
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						(74)	
43		Accumulated Depreciation						(821,969)	$ (821,969)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(821,969)	(821,969)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(822,479)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (821,969)	$ 510
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	266
4	310.1	Water Rights	0.00%	0.00%	1,666			-	6,518
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	13,010
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%				14,749	569,446
8	320	Pumping Plant Land	0.00%	0.00%				-	1,644
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				120	4,633
10	325	Electtric Pumping Equipment	2.59%	2.59%	3,827			8,890	345,146
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	8,815			827	36,356
14	332	Water Treatment Equipment	2.59%	2.59%				1,829	70,610
15	340	Transmission and Distribution Land	0.00%	0.00%				-	3,431
16	342	Storage Tanks	2.59%	2.59%				5,355	206,750
17	343	Transmission & Distribution Mains	2.59%	2.59%	156,917	(372)		35,394	1,444,821
18	344	Fire Sprinkler Taps	2.59%	2.59%				155	6,004
19	345	Services	2.59%	2.59%	60,575	(183)		11,298	466,405
20	346	Meters	2.59%	2.59%	50	(26)		1,429	55,195
21	348	Hydrants	2.59%	2.59%	(1,139)			623	23,499
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				1,225	47,290
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%				11	410
26	393	Warehouse Equipment	2.59%	2.59%	748			10	748
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%				277	10,688
28	395	Laboratory Equipment	2.59%	2.59%				-	-
29	396	Power Operated Equipment	2.59%	2.59%				168	6,486
30	397	Communication Equipment	2.59%	2.59%				886	34,206
31	398	Miscellaneous Equipment	2.59%	2.59%				16	622
32		**TOTAL DIRECT WATER PLANT**			$ 231,459	$ (581)	$ -	$ 83,261	$ 3,354,184
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 231,459	$ (581)	$ -	$ 83,261	$ 3,354,184
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						-	
43		Accumulated Depreciation						(904,649)	$ (904,649)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(904,649)	(904,649)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(905,159)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (904,649)	$ 510
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) DEPRECIATION RATE Decision 64282 1/1/2002 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				-	266
4	310.1	Water Rights	0.00%	0.00%	2,797			-	9,315
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	13,010
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	762			14,759	570,208
8	320	Pumping Plant Land	0.00%	0.00%				-	1,644
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				120	4,633
10	325	Electtric Pumping Equipment	2.59%	2.59%	6,634	(1,314)		9,008	350,466
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%	275			945	36,630
14	332	Water Treatment Equipment	2.59%	2.59%	265,496			5,267	336,106
15	340	Transmission and Distribution Land	0.00%	0.00%				-	3,431
16	342	Storage Tanks	2.59%	2.59%				5,355	206,750
17	343	Transmission & Distribution Mains	2.59%	2.59%	94,745	(1,245)		38,632	1,538,321
18	344	Fire Sprinkler Taps	2.59%	2.59%				155	6,004
19	345	Services	2.59%	2.59%	49,637	(69)		12,722	515,973
20	346	Meters	2.59%	2.59%	10,119	(53)		1,560	65,261
21	348	Hydrants	2.59%	2.59%				609	23,499
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				1,225	47,290
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%				11	410
26	393	Warehouse Equipment	2.59%	2.59%				19	748
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%	499			283	11,187
28	395	Laboratory Equipment	2.59%	2.59%	238			3	238
29	396	Power Operated Equipment	2.59%	2.59%				168	6,486
30	397	Communication Equipment	2.59%	2.59%				886	34,206
31	398	Miscellaneous Equipment	2.59%	2.59%				16	622
32		**TOTAL DIRECT WATER PLANT**			$ 431,199	$ (2,681)	$ -	$ 91,742	$ 3,782,702
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 431,199	$ (2,681)	$ -	$ 91,742	$ 3,782,702
35									
36		**Company Direct Plant As Filed**							
37									
38		**RUCO Direct Plant Adjustment**							
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						(18)	
43		Accumulated Depreciation						(993,727)	$ (993,727)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(993,727)	(993,727)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(994,237)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (993,727)	$ 510
49									
50		**RUCO Net Adjustment**							
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEPRECIATION RATE Decision 58120 1/1/1993 To 12/31/2001	(B) Decision 64282 1/1/2002 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%	0.00%				$ -	$ -
2	302	Franchises	See Acct. 111	See Acct. 111				-	-
3	303	Other Intangibles	See Acct. 111	See Acct. 111				13	266
4	310.1	Water Rights	0.00%	0.00%	4,886			-	14,201
5	310.3	Other Source of Supply Land	0.00%	0.00%				-	13,010
6	310.4	Wells - Other	See Acct. 111	See Acct. 111				-	-
7	314	Wells	2.59%	2.59%	37			14,769	570,245
8	320	Pumping Plant Land	0.00%	0.00%				-	1,644
9	321	Pumping Plant Structures & Imprm'ts	2.59%	2.59%				120	4,633
10	325	Electtric Pumping Equipment	2.59%	2.59%	78,289	(15,287)		9,893	413,468
11	328	Gas Engine Equipment	2.59%	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%	0.00%				-	-
13	331	Water Treatment Structures & Imprm'ts	2.59%	2.59%				949	36,630
14	332	Water Treatment Equipment	2.59%	2.59%				8,705	336,106
15	340	Transmission and Distribution Land	0.00%	0.00%				-	3,431
16	342	Storage Tanks	2.59%	2.59%				5,355	206,750
17	343	Transmission & Distribution Mains	2.59%	2.59%	758,403	(194)		49,661	2,296,530
18	344	Fire Sprinkler Taps	2.59%	2.59%	25,512			486	31,516
19	345	Services	2.59%	2.59%	180,075	(1,396)		15,678	694,652
20	346	Meters	2.59%	2.59%	6,520	(13)		1,775	71,768
21	348	Hydrants	2.59%	2.59%	27,725			968	51,223
22	389	General Plant Land	0.00%	0.00%				-	-
23	390	General Plant Structures	2.59%	2.59%				1,225	47,290
24	390.1	Leasehold Improvements	See Acct. 108.2	See Acct. 108.2				-	-
25	391	Office Furniture & Equipment	2.59%	2.59%				11	410
26	393	Warehouse Equipment	2.59%	2.59%				19	748
27	394	Tools, Shop & Garage Equipment	2.59%	2.59%				290	11,187
28	395	Laboratory Equipment	2.59%	2.59%				6	238
29	396	Power Operated Equipment	2.59%	2.59%	2,393			199	8,879
30	397	Communication Equipment	2.59%	2.59%				886	34,206
31	398	Miscellaneous Equipment	2.59%	2.59%				16	622
32		**TOTAL DIRECT WATER PLANT**			$ 1,083,841	$ (16,890)	$ -	$ 111,022	$ 4,849,654
33		Post Test Year Plant (PTYP)			-	-	-	-	-
34		**RUCO Total Water Plant In Service**			$ 1,083,841	$ (16,890)	$ -	$ 111,022	$ 4,849,654
35									
36		**Company Direct Plant As Filed**							4,849,656
37									
38		**RUCO Direct Plant Adjustment**							$ (2)
39									
40		Reserve Deficiency Accrual - Decision No. 38733						-	
41									
42		Net (Salvage)/Cost of Removal						-	
43		Accumulated Depreciation						(1,087,860)	$ (1,087,860)
44		Accumulated Depreciation - PTYP						-	-
45		RUCO Total Accumulated Depreciation - Calculated						(1,087,860)	(1,087,860)
46									
47		Company As Filed - Accumulated Depreciation			-	-	-	-	(1,088,370)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**			$ -	$ -	$ -	$ (1,087,860)	$ 510
49									
50		**RUCO Net Adjustment**							$ 508
51									
52									
53									

54 References:
55 Column (A): Approved Depreciation Rate From Decision No. 58120
56 Columns (B): Approved Depreciation Rate From Decision No. 66849
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2003 12/31/2003 Per Decision 68302	2003 ADJ-1 Remove Post Test Year Plant	2003 Balance 12/31/2003
1	301	Organization	0.00%	651		651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.	8,496		8,496
4	310.1	Water Rights	0.00%	-		-
5	310.3	Other Source of Supply Land	0.00%	-		-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
7	314	Wells	2.59%	-		-
8	320	Pumping Plant Land	0.00%	-		-
9	321	Pumping Plant Structures and Improvements	2.59%	-		-
10	325	Electric Pumping Equipment	2.59%	-		-
11	328	Gas Engine Equipment	2.59%	-		-
12	330	Water Treatment Plant Land	0.00%	-		-
13	331	Water Treatment Structures and Improvements	2.59%	-		-
14	332	Water Treatment Equipment	2.59%	-		-
15	340	Transmission and Distribution Land	0.00%	-		-
16	342	Storage Tanks	2.59%	-		-
17	343	Transmission and Distribution Mains	2.59%	-		-
18	344	Fire Sprinkler Taps	2.59%	-		-
19	345	Services	2.59%	-		-
20	346	Meters	2.59%	-		-
21	348	Hydrants	2.59%	-		-
22	389	General Plant Land	0.00%	-		-
23	390	General Plant Structures	2.59%	31,795		31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	1,267,373		1,267,373
25	391	Office Furniture and Equipment	2.59%	3,505,411		3,505,411
26	393	Warehouse Equipment	2.59%	3,705		3,705
27	394	Tools, Shop and Garage Equipment	2.59%	30,450		30,450
28	395	Laboratory Equipment	2.59%	977		977
29	396	Power Operated Equipment	2.59%	-		-
30	397	Communication Equipment	2.59%	143,052		143,052
31	398	Miscellaneous Equipment	2.59%	7,207		7,207
32		**TOTAL PHOENIX OFFICE PLANT**		4,999,117	-	4,999,117
33		Post Test Year Plant (PTYP)		-	-	-
34		**RUCO Total Phoenix Office**		4,999,117	-	4,999,117
35						
36		**Company Phoenix Office As Filed**		4,999,117		4,999,117
37						
38		RUCO Phoenix Office Plant Adjustment		-		-
39						
40		Reserve Deficiency Accrual - Dec. 38733		-		-
41						
42		Net (Salvage)/Cost of Removal				
43		Accumulated Depreciation		(503,775)	-	(503,775)
44		Accumulated Depreciation - PTYP		-	-	-
45		RUCO Total Accumulated Depreciation - Calculated		(503,775)	-	(503,775)
46						
47		Company As Filed - Accumulated Depreciation				(503,775)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**				-
49						
50		**RUCO Net Adjustment**				
51						
52						
53						
54						
55						

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
			Dec. 58120 1/1/1993 To Present					
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Im	48,512			78,228	1,315,885
25	391	Office Furniture and Equipment	2.59%	129,135	(7,465)		92,366	3,627,081
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	24,820			1,110	55,270
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	6,465			3,789	149,517
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		208,932	(7,465)	-	176,624	5,200,584
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,200,584
35								
36		**Company Phoenix Office As Filed**						5,200,584
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41							-	
42		Net (Salvage)/Cost of Removal					(672,934)	(672,934)
43		Accumulated Depreciation					-	-
44		Accumulated Depreciation - PTYP					(672,934)	(672,934)
45		RUCO Total Accumulated Depreciation - Calculated						
46								
47		Company As Filed - Accumulated Depreciation						(672,934)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(0)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other Intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
			Dec. 58120 1/1/1993 To Present					
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Im				89,580	1,315,885
25	391	Office Furniture and Equipment	2.59%	221,339			96,808	3,848,420
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	20,585			1,698	75,855
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	885			3,884	150,402
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		242,809	-	-	193,101	5,443,393
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,443,393
35								
36		**Company Phoenix Office As Filed**						5,443,393
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(866,035)	(866,035)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(866,035)	(866,035)
46								
47		Company As Filed - Accumulated Depreciation						(866,035)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				823	31,795
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Im				94,864	1,315,885
25	391	Office Furniture and Equipment	2.59%	369,071			104,454	4,217,491
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	59,519			2,735	135,374
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	1,741			3,918	152,143
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		430,332	-	-	207,102	5,873,725
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						5,873,725
35								
36		**Company Phoenix Office As Filed**						5,873,725
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(1,073,138)	(1,073,138)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(1,073,138)	(1,073,138)
46								
47		Company As Filed - Accumulated Depreciation						(1,073,137)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(1)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Phoenix Office

Line No.	Acct. No.	Description	Depreciation Rate	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
			Dec. 58120 1/1/1993 To Present					
1	301	Organization	0.00%				-	651
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				425	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	8,496
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	-
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				-	-
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				-	-
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	10,463			959	42,258
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Im	93			86,708	1,315,978
25	391	Office Furniture and Equipment	2.59%	464,535	(243,714)		112,093	4,438,312
26	393	Warehouse Equipment	2.59%				96	3,705
27	394	Tools, Shop and Garage Equipment	2.59%	40,312			4,028	175,686
28	395	Laboratory Equipment	2.59%				25	977
29	396	Power Operated Equipment	2.59%				-	-
30	397	Communication Equipment	2.59%	4,089			3,993	156,232
31	398	Miscellaneous Equipment	2.59%				187	7,207
32		**TOTAL PHOENIX OFFICE PLANT**		519,493	(243,714)	-	208,514	6,149,503
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Phoenix Office**						6,149,503
35								
36		**Company Phoenix Office As Filed**						6,149,503
37								
38		RUCO Phoenix Office Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(1,037,938)	(1,037,938)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(1,037,938)	(1,037,938)
46								
47		Company As Filed - Accumulated Depreciation						(1,036,382)
48		**RUCO Direct Plant Accumulated Depreciation Adjustment**						(1,556)
49								
50		**RUCO Net Adjustment**						(1,556)
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2003 12/31/2003 Per Decision 68302	2003 ADJ-1 Remove Post Test Year Plant	2003 Balance 12/31/2003
1	301	Organization	0.00%	-		-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
4	310.1	Water Rights	0.00%	-		-
5	310.3	Other Source of Supply Land	0.00%	80		80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.	-		-
7	314	Wells	2.59%	-		-
8	320	Pumping Plant Land	0.00%	-		-
9	321	Pumping Plant Structures and Improvements	2.59%	-		-
10	325	Electric Pumping Equipment	2.59%	-		-
11	328	Gas Engine Equipment	2.59%	-		-
12	330	Water Treatment Plant Land	0.00%	-		-
13	331	Water Treatment Structures and Improvements	2.59%	-		-
14	332	Water Treatment Equipment	2.59%	2,050		2,050
15	340	Transmission and Distribution Land	0.00%	-		-
16	342	Storage Tanks	2.59%	-		-
17	343	Transmission and Distribution Mains	2.59%	6,066		6,066
18	344	Fire Sprinkler Taps	2.59%	-		-
19	345	Services	2.59%	-		-
20	346	Meters	2.59%	-		-
21	348	Hydrants	2.59%	-		-
22	389	General Plant Land	0.00%	-		-
23	390	General Plant Structures	2.59%	37,472		37,472
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Impr.	-		-
25	391	Office Furniture and Equipment	2.59%	3,983		3,983
26	393	Warehouse Equipment	2.59%	1,088		1,088
27	394	Tools, Shop and Garage Equipment	2.59%	58,430		58,430
28	395	Laboratory Equipment	2.59%	2,981		2,981
29	396	Power Operated Equipment	2.59%	1,458		1,458
30	397	Communication Equipment	2.59%	-		-
31	398	Miscellaneous Equipment	2.59%	-		-
32		**TOTAL METER SHOP PLANT**		113,608	-	113,608
33		Post Test Year Plant (PTYP)		-	-	-
34		**RUCO Total Meter Shop**		113,608	-	113,608
35						
36		**Company Meter Shop As Filed**		113,608		113,608
37						
38		RUCO Meter Shop Plant Adjustment		-		-
39						
40		Reserve Deficiency Accrual - Dec. 38733				
41						
42		Net (Salvage)/Cost of Removal				
43		Accumulated Depreciation		(30,118)	-	(30,118)
44		Accumulated Depreciation - PTYP		-	-	-
45		RUCO Total Accumulated Depreciation - Calculated		(30,118)	-	(30,118)
46						
47		Company As Filed - Accumulated Depreciation				(30,118)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**				-
49						
50		**RUCO Net Adjustment**				
51						
52						
53						
54						
55						
56		Notes				
57		Acct. 302 - Franchises amortized over 25 years.				
58		Acct. 303 - Other intangibles amortized over 15 & 20 Years.				
59		Acct. 310.4 - Wells - Other amortized over 24 years.				
60		Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.				

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2004 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2004
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	12,809			1,136	50,281
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Im				-	-
25	391	Office Furniture and Equipment	2.59%	3,166			144	7,149
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	1,575			1,534	60,005
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		17,550	-	-	3,168	131,158
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						131,158
35								
36		**Company Meter Shop As Filed**						131,158
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733						
41								
42		Net (Salvage)/Cost of Removal					-	
43		Accumulated Depreciation					(33,286)	(33,286)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(33,286)	(33,286)
46								
47		Company As Filed - Accumulated Depreciation						(33,286)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2005 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2005
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				1,302	50,281
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Im				-	-
25	391	Office Furniture and Equipment	2.59%	94			186	7,243
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	2,004			1,580	62,009
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		2,097	-	-	3,422	133,256
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						133,256
35								
36		**Company Meter Shop As Filed**						133,256
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(36,708)	(36,708)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(36,708)	(36,708)
46								
47		Company As Filed - Accumulated Depreciation						(36,708)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						0
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								

56 Notes
57 Acct. 302 - Franchises amortized over 25 years.
58 Acct. 303 - Other intangibles amortized over 15 & 20 Years.
59 Acct. 310.4 - Wells - Other amortized over 24 years.
60 Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2006 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2006
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%	2,571			1,336	52,852
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Im				-	-
25	391	Office Furniture and Equipment	2.59%	1,610			208	8,853
26	393	Warehouse Equipment	2.59%				28	1,088
27	394	Tools, Shop and Garage Equipment	2.59%	3,115			1,646	65,124
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		7,296	-	-	3,544	140,551
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						140,551
35								
36		**Company Meter Shop As Filed**						140,551
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(40,251)	(40,251)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(40,251)	(40,251)
46								
47		Company As Filed - Accumulated Depreciation						(40,251)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						(0)
49								
50		**RUCO Net Adjustment**						
51								
52								
53								
54								
55								
56		Notes						
57		Acct. 302 - Franchises amortized over 25 years.						
58		Acct. 303 - Other intangibles amortized over 15 & 20 Years.						
59		Acct. 310.4 - Wells - Other amortized over 24 years.						
60		Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.						

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007
Plant Reconciliation Schedule - Meter Shop

Line No.	Acct. No.	Description	Depreciation Rate Dec. 58120 1/1/1993 To Present	2007 Additions	Retirements	Adjustments	Depreciation Expense	Balance 12/31/2007
1	301	Organization	0.00%				-	-
2	302	Franchises	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
3	303	Other Intangibles	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
4	310.1	Water Rights	0.00%				-	-
5	310.3	Other Source of Supply Land	0.00%				-	80
6	310.4	Wells - Other	See Acct. 111 - Amort of Ltd. Trm. Inv.				-	-
7	314	Wells	2.59%				-	-
8	320	Pumping Plant Land	0.00%				-	-
9	321	Pumping Plant Structures and Improvements	2.59%				-	-
10	325	Electric Pumping Equipment	2.59%				-	-
11	328	Gas Engine Equipment	2.59%				-	-
12	330	Water Treatment Plant Land	0.00%				-	-
13	331	Water Treatment Structures and Improvements	2.59%				-	-
14	332	Water Treatment Equipment	2.59%				53	2,050
15	340	Transmission and Distribution Land	0.00%				-	-
16	342	Storage Tanks	2.59%				-	-
17	343	Transmission and Distribution Mains	2.59%				157	6,066
18	344	Fire Sprinkler Taps	2.59%				-	-
19	345	Services	2.59%				-	-
20	346	Meters	2.59%				-	-
21	348	Hydrants	2.59%				-	-
22	389	General Plant Land	0.00%				-	-
23	390	General Plant Structures	2.59%				1,369	52,852
24	390.1	Leasehold Improvements	See Acct. 108.2 - Amort of Leasehold Im				-	-
25	391	Office Furniture and Equipment	2.59%	1,893			254	10,745
26	393	Warehouse Equipment	2.59%	1,089			42	2,177
27	394	Tools, Shop and Garage Equipment	2.59%	2,298			1,716	67,422
28	395	Laboratory Equipment	2.59%				77	2,981
29	396	Power Operated Equipment	2.59%				38	1,458
30	397	Communication Equipment	2.59%				-	-
31	398	Miscellaneous Equipment	2.59%				-	-
32		**TOTAL METER SHOP PLANT**		5,280	-	-	3,707	145,832
33		Post Test Year Plant (PTYP)						-
34		**RUCO Total Meter Shop**						145,832
35								
36		**Company Meter Shop As Filed**						145,832
37								
38		RUCO Meter Shop Plant Adjustment						-
39								
40		Reserve Deficiency Accrual - Dec. 38733					-	
41								
42		Net (Salvage)/Cost of Removal					-	-
43		Accumulated Depreciation					(43,958)	(43,958)
44		Accumulated Depreciation - PTYP					-	-
45		RUCO Total Accumulated Depreciation - Calculated					(43,958)	(43,958)
46								
47		Company As Filed - Accumulated Depreciation						(43,959)
48		**RUCO Meter Shop Plant Accumulated Depreciation Adjustment**						1
49								
50		**RUCO Net Adjustment**						1
51								
52								
53								
54								
55								
56		Notes						
57		Acct. 302 - Franchises amortized over 25 years.						
58		Acct. 303 - Other intangibles amortized over 15 & 20 Years.						
59		Acct. 310.4 - Wells - Other amortized over 24 years.						
60		Acct. 390.1 - Leasehold Improvements amortized over the remaining life of the associated lease.						

EXPLANATION OF RATE BASE ADJUSTMENT NO. 2
POST TEST-YEAR PLANT - PHOENIX OFFICE

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) COMPANY ADJUSTED TY PLANT	(B) POST TY ADDITIONS	(C) 3-FACTOR ALLOCATOR	(D) REMOVE PTY PLANT
1	301	Organization	$ 10	$ -	1.48%	$ -
2	302	Franchises	-	-	1.48%	-
3	303	Other Intangibles	392	-	1.48%	-
4	310.1	Water Rights	14,201	-	1.48%	-
5	310.3	Other Source of Supply Land	13,011	-	1.48%	-
6	310.4	Wells - Other	-	-	1.48%	-
7	314	Wells	570,245	-	1.48%	-
8	320	Pumping Plant Land	1,644	-	1.48%	-
9	321	Pumping Plant Structures & Imprm'ts	4,633	-	1.48%	-
10	325	Electtric Pumping Equipment	413,468	-	1.48%	-
11	328	Gas Engine Equipment	-	-	1.48%	-
12	330	Water Treatment Plant Land	-	-	1.48%	-
13	331	Water Treatment Structures & Imprm'ts	36,630	-	1.48%	-
14	332	Water Treatment Equipment	336,136	-	1.48%	-
15	340	Transmission and Distribution Land	3,431	-	1.48%	-
16	342	Storage Tanks	206,750	-	1.48%	-
17	343	Transmission & Distribution Mains	2,296,620	-	1.48%	-
18	344	Fire Sprinkler Taps	31,516	-	1.48%	-
19	345	Services	694,652	-	1.48%	-
20	346	Meters	71,768	-	1.48%	-
21	348	Hydrants	51,223	-	1.48%	-
22	389	General Plant Land	-	-	1.48%	-
23	390	General Plant Structures	48,698	-	1.48%	-
24	390.1	Leasehold Improvements	19,476	-	1.48%	-
25	391	Office Furniture & Equipment	66,256	120,057	1.48%	1,777
26	393	Warehouse Equipment	835	-	1.48%	-
27	394	Tools, Shop & Garage Equipment	14,785	-	1.48%	-
28	395	Laboratory Equipment	296	-	1.48%	-
29	396	Power Operated Equipment	8,901	-	1.48%	-
30	397	Communication Equipment	36,518	-	1.48%	-
31	398	Miscellaneous Equipment	729	-	1.48%	-
32		Rounding	2			
33		**TOTAL PTY WATER PLANT**	$ 4,942,827	$ 120,057		$ 1,777
34		Company As Filed	$ 4,942,827	120,057		1,777
35		Difference	$ -	$ -		$ -
36						
37		RUCO PTY Plant Adjustment				$ (1,777)
38						
39		RUCO PTY Accumulated Depreciation Plant Adjustment				$ 59
40						
41						
42	References:					
43	Column (A): Company Schedules B-2					
44	Column (B): Post Test Year Phoenix Office Plant Allocation					
45	Column (C): 3-Factor Allocator					
46	Column (D): Adjustment					

EXPLANATION OF RATE BASE ADJUSTMENT NO. 6
ALLOWANCE FOR WORKING CAPITAL

LINE NO.	DESCRIPTION	(A) AMOUNT	(B) REFERENCE
1	Working Cash Requirement Per Company	$ 29,652	Company Schedule B-5, PG. 1
2	Working Cash Requirement Per RUCO	(12,058)	RUCO Schedule WAR-5, Page 2
3	Adjustment	$ (41,710)	Line 2 - Line 1
4	Material and Supplies Inventories Per Company	$ 10,117	Company Schedule B-5, PG. 1
5	Material and Supplies Inventories Per RUCO	10,117	Company Schedule B-5, PG. 1
6	Adjustment	$ -	Line 5 - Line 4
7	Required Bank Balances Per Company	$ 7,613	Company Schedule B-5, PG. 1
8	Required Bank Balances Per RUCO	7,613	Company Schedule B-5, PG. 1
9	Adjustment	$ -	Line 8 - Line 7
10	Prepayments & Special Deposits Per Company	$ 7,949	Company Schedule B-5, PG. 1
11	Prepayments & Special Deposits Per RUCO	7,949	Company Schedule B-5, PG. 1
12	Adjustment	$ -	Line 11 - Line 10
13	TOTAL ADJUSTMENT (See WAR-2, Column (K))	$ (41,710)	Sum of Lines 3, 6, 9 & 12

EXPLANATION OF RATE BASE ADJUSTMENT NO. 6 - CONT'D
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
	Operating Expenses					
1	Purchased Power	$ 43,401	$ -	$ 43,401	35.92	$ 1,558,964
2	Payroll	133,621	(4,481)	129,140	14.00	1,807,965
3	Purchased Water	-	-	-	-	-
4	Chemicals	2,079	-	2,079	20.43	42,467
5	Property & Liability Insurance	4,421	-	4,421	(45.27)	(200,139)
6	Workman's Compensation Insurance	2,210	-	2,210	(46.50)	(102,765)
7	Health Insurance	33,272	(16)	33,256	(8.92)	(296,640)
8	Other Operating & Maintenance Expenses	286,170	(2,467)	283,703	30.00	8,511,075
9	Federal Current Income Taxes	73,535	(40,888)	32,647	37.00	1,207,946
10	State Current Income Taxes	16,199	(6,712)	9,487	37.00	351,007
11	FICA Taxes	9,941	(712)	9,229	14.00	129,201
12	FUTA & SUTA Taxes	238	-	238	83.10	19,778
13	Property Taxes	27,191	(2,623)	24,568	212.00	5,208,319
14	Registration, Svc. Contracts, & Misc. Fees	8,415	-	8,415	(98.83)	(831,654)
15	Retirement Annuities (401k)	10,982	(364)	10,618	34.72	368,647
16	Subtotal	651,674	(58,264)	593,410		17,774,170
17	Synchronized Interest	$ 86,714	$ (1,658)	$ 85,056	91.25	$ 7,761,327
18	Cost of Equity	142,744	(142,744)	-	-	-
19	Subtotal	$ 229,458	$ (144,402)	$ 85,056		$ 7,761,327
20	Total	$ 881,132	$ (202,666)	$ 678,466		$ 25,535,498

21	Expense Lag	Line 17, Col. (E) / (C)	37.64
22	Revenue Lag	Company B-5 Schedules	31.15
23	Net Lag	Line 18 - Line 17	(6.49)
24	RUCO Adjusted Expenses	Col. (C), Line 16	$ 678,466
25	Cash Working Capital	Line 19 X Line 20 / 365 Days	(12,058)
26	Company As Filed	Co. Schedule B-6, Page 1	29,652
27	Difference	Line 21 - Line 22	$ (41,710)
28	ADJUSTMENT	Line 27	$ (41,710)

NOTE: Expense Lag Days Used in the Last Western Group Rate Case.

NOTE: RUCO reviewed several invoices from a number of companies with terms of net 30 days.

References:
Column (A): - Company Schedule B-5
Column (B): RUCO Operating Income Adjustments (See Schedule WAR-7)
Column (C): Column (A) + (B)
Column (D): - Company Schedule B-5
Column (E): Column (C) X Column (D)

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 471,523	$ (436)	$ 471,087	$ 337,175	$ 808,263
2	Commercial	17,845	(14)	17,831	17,593	35,424
3	Industrial	-	-	-	-	-
4	Private Fire Service	51	-	51	199	250
5	Other Water Revenues	10,101	(19)	10,082	11,103	21,185
6	Total Water Revenues	$ 499,521	$ (469)	$ 499,051	$ 366,071	$ 865,122
7	Miscellaneous	$ 8,461	$ -	$ 8,461	$ 306	$ 8,766
8	Total Operating Revenues	$ 507,981	$ (469)	$ 507,512	$ 366,376	$ 873,888
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	1,425	-	1,425	-	1,425
11	Pumping Expenses:	-				
12	Purchased Power	43,401	-	43,401	-	43,401
13	Purchased Gas	-	-	-	-	-
14	Other	24,368	-	24,368	-	24,368
15	Water Treatment Expenses	201,774	-	201,774	-	201,774
16	Transmission & Distribution Expenses	73,189	-	73,189	-	73,189
17	Customer Accounting Expenses	61,306	-	61,306	-	61,306
18	Sales Expense	537	-	537	-	537
19	Administrative & General Expenses	118,572	(25,668)	92,905	-	92,905
20	Total Operations & Maintenance Expense	$ 524,571	$ (25,668)	$ 498,904	$ -	$ 498,904
21	Depreciation & Amortization Expenses	$ 124,861	$ (3,352)	$ 121,508	$ -	$ 121,508
	Taxes					
22	Federal Income Taxes	$ (83,435)	$ 28,226	$ (55,208)	$ 87,855	$ 32,647
23	State Income Taxes	(18,380)	2,337	(16,042)	25,529	9,487
24	Property Taxes	27,191	(2,623)	24,567	-	24,567
25	Other	8,420	(712)	7,707	-	7,707
26	Total Taxes	$ (66,204)	$ 27,228	$ (38,976)	$ 113,384	$ 74,408
27	Total Operating Expenses	$ 583,228	$ (1,792)	$ 581,436	$ 113,384	$ 694,820
28	Operating Income	$ (75,247)	$ 1,323	$ (73,924)	$ 252,992	$ 179,068

References:
Column (A): Company Schedule C-1
Column (B): WAR-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): WAR-1
Column (E): Column (C) + Column (D)

Arizona Water Company
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Test Year Ended December 31, 2007

Rimrock System
Schedule WAR-8
Page 1 of 1

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 471,523	$ -	$ -	$ -	$ (436)	$ -	$ -	$ -	$ -	$ -	$ -	$ 471,087
2	Commercial	17,845	-	-	-	(14)	-	-	-	-	-	-	17,831
3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-
4	Private Fire Service	51	-	-	-	-	-	-	-	-	-	-	51
5	Other Water Revenues	10,101	-	-	-	(19)	-	-	-	-	-	-	10,082
6	Total Water Revenues	$ 499,521	$ -	$ -	$ -	$ (469)	$ -	$ -	$ -	$ -	$ -	$ -	$ 499,051
7	Miscellaneous	$ 8,461	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,461
8	Total Operating Revenues	$ 507,981	$ -	$ -	$ -	$ (469)	$ -	$ -	$ -	$ -	$ -	$ -	$ 507,512
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	1,425	-	-	-	-	-	-	-	-	-	-	1,425
11	Pumping Expenses:												
12	Purchased Power	43,401	-	-	-	-	-	-	-	-	-	-	43,401
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	24,368	-	-	-	-	-	-	-	-	-	-	24,368
15	Water Treatment Expenses	201,774	-	-	-	-	-	-	-	-	-	-	201,774
16	Transmission & Distribution Expenses	73,189	-	-	-	-	-	-	-	-	-	-	73,189
17	Customer Accounting Expenses	61,306	-	-	-	-	-	-	-	-	-	-	61,306
18	Sales Expense	537	-	-	-	-	-	-	-	-	-	-	537
19	Administrative & General Expenses	118,572	(4,481)	-	(364)	-	(19,820)	(16)	-	-	(987)	-	92,905
20	Total Operations & Maintenance Expense	$ 524,571	$ (4,481)	$ -	$ (364)	$ -	$ (19,820)	$ (16)	$ -	$ -	$ (987)	$ -	$ 498,904
21	Depreciation & Amortization Expenses	$ 124,861	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,352)	$ -	$ -	$ -	$ 121,508
	Taxes												
22	Federal Income Taxes	$ (83,435)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,226	$ (55,208)
23	State Income Taxes	(18,380)	-	-	-	-	-	-	-	-	-	2,337	(16,042)
24	Property Taxes	27,191	-	-	-	-	-	-	-	(2,623)	-	-	24,567
25	Other	8,420	-	(712)	-	-	-	-	-	-	-	-	7,707
26	Total Taxes	$ (66,204)	$ -	$ (712)	$ -	$ -	$ -	$ -	$ -	$ (2,623)	$ -	$ 30,564	$ (38,976)
27	Total Operating Expenses	$ 583,228	$ (4,481)	$ (712)	$ (364)	$ -	$ (19,820)	$ (16)	$ (3,352)	$ (2,623)	$ (987)	$ 30,564	$ 581,436
28	Operating Income	$ (75,247)	$ 4,481	$ 712	$ 364	$ (469)	$ 19,820	$ 16	$ 3,352	$ 2,623	$ 987	$ (30,564)	$ (73,924)

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule WAR-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule WAR-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule WAR-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule WAR-10
7 - Depreciation Expense	Testimony, WAR And Schedule WAR-11
8 - Property Tax Expense	Testimony, WAR And Schedule WAR-12
9 - Rate Case Expense	Testimony, WAR And Schedule WAR-13
10 - Income Tax	Testimony, WAR And Schedule WAR-14

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
PAYROLL EXPENSE

LINE NO.	DESCRIPTION		(A) PER RUCO DR 1.11.d
1	Normalize Over-Time Over 4 Years:		
2	2005 OT Hours		15,008.5
3	2006 OT Hours		18,080.0
4	2007 OT Hours		28,132.5
5	2008 OT Hours		17,530.0
6			
7	Total OT Hours for 2005 - 2008		78,751.0
8	Divided by 4 Years		4
9			
10	Normalized Level of OT Hours/Yr.		19,687.8
11			
12	OT Hours in Test Year		28,132.5
13			
14	Amount of Abnormal TY OT Hours		8,444.8
15			
16	Multiplied by Average OT Hrly. Rate	**See NOTE**	35.85
17			
18	Total Abnormal OT Dollars in TY		$ 302,744
19			
20	3-Factor Allocator Per District		1.48%
21			
22	RUCO Adjustment		$ (4,481)
23			
24			
25			
26			
27			
28	3-Factor Allocator By District:		
29	Superstition	24.94%	White Tank 2.37%
30	Bisbee	4.98%	Ajo 0.81%
31	Sierra Vista	2.58%	Coolidge 5.27%
32	San Manuel	1.68%	Lakeside 6.20%
33	Oracle	2.28%	Overgaard 3.99%
34	Winkelman	0.22%	Sedona 8.45%
35	Miami	4.98%	Pinewood 2.95%
36	Casa Grande	26.55%	Rimrock 1.48%
37	Stanfield	0.27%	
38			
39			
40			
41			
42	**Calculation Notes:**		
43	Average of Hourly Rate	$ 21.65	
44	OT Hourly Rate 1.5	32.48	

NOTE: The Company calculated the average hourly rate for overtime in response to data request AII-11.6 to be $35.85. RUCO accepts that rate in making its payroll adjustments.

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PAYROLL TAX EXPENSE ASSOCIATED WITH RUCO ADJUSTMENT 1

LINE NO.	DESCRIPTION	(A) PER RUCO DR 1.11.d
1	Payroll Tax Expense:	
2		
3	Total Abnormal OT Dollars in TY	$ 302,744
4		
5	3-Factor Allocator Per District	1.48%
6		
7	RUCO Allocated Payroll by District	$ 4,481
8		
9	Payroll Tax Expense Allocator By Group:	
10		
11	RUCO Payroll Tax Expense Allocator by Group	15.90%
12		
13	RUCO Payroll Tax Expense Adjustment	$ (712)
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Payroll Tax Expense Allocator By Group:	
39	Eastern Group 7.47%	
40	Western Group 11.65%	
41	Northern Group 15.90%	

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
PAYROLL 401(K) EXPENSE ASSOCIATED WITH RUCO ADJUSTMENT 1

LINE NO.	DESCRIPTION	(A) PER RUCO DR 1.11.d
1	Payroll 401(K) Expense:	
2		
3	Total Abnormal OT Dollars in TY	$ 302,744
4		
5	3-Factor Allocator Per District	1.48%
6		
7	RUCO Allocated Payroll by District	$ 4,481
8		
9	Payroll 401(K) Expense Allocator By Group:	
10		
11	RUCO Payroll 401(K) Expense Allocator by Group	8.12%
12		
13	RUCO Payroll 401(K) Expense Adjustment	$ (364)
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Payroll Tax Expense Allocator By Group:	
39	Eastern Group	8.39%
40	Western Group	8.45%
41	Northern Group	8.12%

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
INSURANCE EXPENSE

LINE NO.		(A) INCREASE/ (DECREASE) LONG-TERM DISABILITY PER COMPANY	(B) RUCO ADJUSTMENT	(C) INCREASE/ (DECREASE) LONG-TERM DISABILITY PER RUCO	
1	System				
2					
3	Eastern Group				
4	Supersition	$ 2,224	$ (273)	$ 1,950	
5	Apache Junction				
6	Superior				
7	Bisbee	122	(45)	77	
8	Sierra Vista	115	(38)	77	
9	San Manuel	5	(20)	(16)	
10	Oracle	25	(20)	5	
11	Saddlebrook	5	(0)	4	
12	Winkelman	0	(2)	(2)	
13	Miami	(338)	(40)	(378)	
14	Subtotal	$ 2,157	$ (439)	$ 1,718	
15					
16	Western Group				
17	Casa Grande	2,137	(298)	1,839	
18	Stanfield	20	(3)	17	
19	White Tank	148	(22)	126	
20	Ajo	58	(9)	49	
21	Coolidge	(127)	(62)	(189)	
22	Subtotal	$ 2,235	$ (393)	$ 1,842	
23					
24	Northern Group				
25	Lakeside	570	(65)	506	
26	Overgaard	507	(55)	452	
27	Sedona	445	(84)	361	
28	Pinewood	199	(38)	162	
29	Rimrock	87	(16)	71	
30	Subtotal	$ 1,809	$ (257)	$ 1,551	
31					
32					
33	Total Company	$ 6,201	$ (1,090)	$ 5,111	(a)

REFERENCE

COLUMN (A): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD
COLUMN (B): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD
COLUMN (C): COMPANY WORKPAPER "GROUP INSURANCE" TAB LTD

NOTES:

(a) CALCULATED AS FOLLOWS:		PER COMPANY	RUCO ADJUSTMENT	PER RUCO	REFERENCE
1	Current Rate per Payroll Dollar	$ 0.0036		$ 0.0036	COMPANY WORKPAPER - "GROUP INSURANCE" TAB LTD
2	Pro Forma Payroll Dollars	$ 11,095,569	$ 302,744	$ 10,792,825	COMPANY WORKPAPER - "GROUP INSURANCE)
3	Pro Forma LTD - Total Company	$ 39,944		$ 38,854	LINE 1 x LINE 2
4	Y/E Number of Customers	$ 83,825		$ 83,825	COMPANY WORKPAPER - "GROUP INSURANCE)
5	Pro Forma 2007 LTD - Spread	$ 38,854		$ 38,854	COMPANY WORKPAPER - "GROUP INSURANCE)
6	Increase / (Decrease)	$ 6,201		$ 5,111	COMPANY WORKPAPER - "GROUP INSURANCE)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 7
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCOUNT NO.	ACCOUNT NAME	(A) RUCO PLANT VALUE	(B) COMPANY PROPOSED DEP. RATES	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization	$ 10	0.00%	$ -
2	302	Franchises	-	See Acct. 111	-
3	303	Other Intangibles	392	See Acct. 111	13
4	310.1	Water Rights	14,201	0.00%	-
5	310.3	Other Source of Supply Land	13,011	0.00%	-
6	310.4	Wells - Other	-	See Acct. 111	-
7	314	Wells	508,148	3.13%	15,905
8	320	Pumping Plant Land	1,644	0.00%	-
9	321	Pumping Plant Structures & Imprm'ts	4,633	2.86%	133
10	325	Electtric Pumping Equipment	413,468	5.88%	24,312
11	328	Gas Engine Equipment	-	4.00%	-
12	330	Water Treatment Plant Land	-	0.00%	-
13	331	Water Treatment Structures & Imprm'ts	36,630	2.50%	916
14	332	Water Treatment Equipment	336,136	2.86%	9,613
15	340	Transmission and Distribution Land	3,431	0.00%	-
16	342	Storage Tanks	206,750	2.00%	4,135
17	343	Transmission & Distribution Mains	2,296,620	1.79%	41,109
18	344	Fire Sprinkler Taps	31,516	2.00%	630
19	345	Services	694,652	2.38%	16,533
20	346	Meters	71,768	4.55%	3,265
21	348	Hydrants	51,223	1.82%	932
22	389	General Plant Land	-	0.00%	-
23	390	General Plant Structures	48,698	2.50%	1,217
24	390.1	Leasehold Improvements	19,476	See Acct. 108.2	-
25	391	Office Furniture & Equipment	64,480	6.67%	4,301
26	393	Warehouse Equipment	835	5.00%	42
27	394	Tools, Shop & Garage Equipment	14,785	4.00%	591
28	395	Laboratory Equipment	296	5.00%	15
29	396	Power Operated Equipment	8,901	6.67%	594
30	397	Communication Equipment	36,518	6.67%	2,436
31	398	Miscellaneous Equipment	729	3.33%	24
32		Rounding	3		
33		TEST YEAR GROSS PLANT AND DEPRECIATION EXPENSE	$ 4,878,954		$ 126,717
34					
35		AMORTIZATION OF CONTRIBUTIONS	(260,411)	2.00%	(5,208)
36		Rounding			-
37	**TOTAL DEPRECIATION EXPENSE**				$ 121,509
38					
39	Company As Filed				124,861
40	Difference				$ (3,352)
41					
42	RUCO Adjustment (See WAR-8, Column (B))				$ (3,352)
43					
44					
45	3-Factor Allocator By District:				
46	Superstition	24.94%	White Tank	2.37%	
47	Bisbee	4.98%	Ajo	0.81%	
48	Sierra Vista	2.58%	Coolidge	5.27%	
49	San Manuel	1.68%	Lakeside	6.20%	
50	Oracle	2.28%	Overgaard	3.99%	
51	Winkelman	0.22%	Sedona	8.45%	
52	Miami	4.98%	Pinewood	2.95%	
53	Casa Grande	26.55%	Rimrock	1.48%	
54	Stanfield	0.27%			

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 8
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A)	(B)
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. WAR-7, Col (C), Ln 8	$ 507,512	
2	Adjusted Revenues In Year Ended December 2007	Sch. WAR-7, Col (C), Ln 8	507,512	
3	Proposed Revenues	Sch. WAR-7, Col (E), Ln 8	873,888	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 1,888,912	
5	Average Annual Operating Revenues	Line 4 / 3	629,637	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 1,259,275
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Company Schedule E	$ 1,857	
8	10% Of CWIP	Line 7 X 10%		$ 186
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	Company Workpapers	$ -	
10	Acc. Dep. Of Transportation Equipment	Company Workpapers	-	
11	Net Book Value Of Transportation Equipment	Line 9 + Line 10		$ (15,849)
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 1,243,611
	Calculation Of The Company's Tax Liability:			
	MULTIPLY:			
	FCV X Valuation Assessment Ratio X Property Tax Rates:			
13	Assessment Ratio	House Bill 2779	22.5%	
14	Assessed Value	Line 12 X Line 13	$ 279,813	
	Property Tax Rates:			
15	Primary Tax Rate	Company Workpapers	8.78%	
16	Secondary Tax Rate	Company Workpapers	0.00%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	8.78%	
	Property Tax			$ 24,568
	Tax On Parcel			-
18	Company's Total Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 24,568
19	Test Year Adjusted Property Tax Expense As Filed	Co. Sch. C-1		27,191
20	Decrease In Property Tax Expense	Line 18 - Line 19		$ (2,623)
21	RUCO Adjustment (See WAR-8, Column (C))	Line 20		$ (2,623)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 9
RATE CASE EXPENSE

LINE NO.	DESCRIPTION	(A) COMPANY ESTIMATE	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total	$ 500,000	$ (200,000)	$ 300,000
2	Allocation Factor			1.48%
3	Rimrock System (Line 1 X Line 2)			$ 4,440
4	Amortization Period - 3 Years			3
5	RUCO Adjusted Rate Case Expense (Line 3 / 3 Years)			$ 1,480
6	Company Rate Case Expenses As Filed (Company Sch. C-2)			$ 2,467
7	RUCO Pro Forma Rate Case Expense (Lines 5 - 6)			$ (987)
8	RUCO Adjustment (Line 7) (See WAR-8, Column (E))			$ (987)

3-Factor Allocator By District:

Superstition	24.94%	White Tank	2.37%
Bisbee	4.98%	Ajo	0.81%
Sierra Vista	2.58%	Coolidge	5.27%
San Manuel	1.68%	Lakeside	6.20%
Oracle	2.28%	Overgaard	3.99%
Winkelman	0.22%	Sedona	8.45%
Miami	4.98%	Pinewood	2.95%
Casa Grande	26.55%	Rimrock	1.48%
Stanfield	0.27%		

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 10
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. WAR-7, Column (C), L28 + L22 + L23	$ (145,175)
	LESS:		
2	Arizona State Tax	Line 11	(16,042)
3	Interest Expense	Note (A) Line 21	85,056
4	Federal Taxable Income	Line 1 - Line 2 - Line 3	$ (214,188)
5	Federal Tax Rate	Sch. WAR-1, Pg 2, Col. (D), L34	25.78%
6	Federal Income Tax Expense	Line 4 X line 5	$ (55,208)
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ (145,175)
	LESS:		
8	Interest Expense	Note (A) Line 21	85,056
9	State Taxable Income	Line 7 - Line 8	$ (230,230)
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ (16,042)
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ (55,208)
13	State Income Tax Expense	Line 11	(16,042)
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ (71,251)
15	Total Federal Income Tax Expense Per Company (Per Company Sch. C-1, L30)		(83,435)
16	Total State Income Tax Expense Per Company (Per Company Sch. C-1, L31)		(18,380)
17	RUCO Federal Income Tax Adjustment	Line 12 - Line 15	$ 28,226
18	RUCO State Income Tax Adjustment	Line 13 - Line 16	$ 2,337

NOTE (A):
Interest Synchronization:

19	Adjusted Rate Base (Sch. WAR-2, Col. (H), L17)	$ 2,293,279
20	Weighted Cost Of Debt (Sch. WAR-16 Col. (F), L1)	3.71%
21	Interest Expense (L18 X L19)	$ 85,056

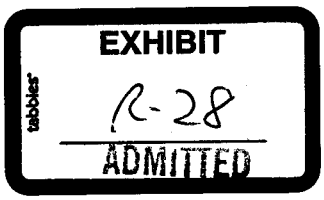
COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Long-Term Debt	$ 75,000,000	50.76%	7.31%	3.71%
2	Common Equity	72,744,646	49.24%	8.33%	4.10%
3	Total Capitalization	$ 147,744,646	100.00%		
4	WEIGHTED AVERAGE COST OF CAPITAL				7.81%

References:
Columns (A) Thru (D): Testimony, WAR

ARIZONA WATER COMPANY

DOCKET NO. W-01445A-08-0440



SURREBUTTAL TESTIMONY ON REQUIRED REVENUE

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 7, 2009

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ATTACHMENT B – NASUCA Resolution on Automatic Adjustment Charges

ABBREVIATED NORTHERN GROUP SCHEDULES

INTRODUCTION

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

A. My name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office, located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes. On June 12, 2009, I filed direct testimony with the ACC. My direct testimony on revenue requirement addressed the operating revenue and expense issues associated with the case. I also filed direct testimony on cost of capital issues.

Q. Please state the purpose of your surrebuttal testimony.

A. The purpose of my surrebuttal testimony is to respond to AWC's rebuttal testimony on RUCO's recommended levels of operating revenue and expense (i.e. operating income) for the Company's seventeen operating systems in Arizona and on RUCO's position on various adjustor mechanisms being proposed by AWC.

Q. Will your surrebuttal testimony address any of the rate base issues in the case?

A. No. Those issues will be addressed in the surrebuttal testimony of RUCO Witness Timothy J. Coley.

Q. Are you also filing surrebuttal testimony on the cost of capital issues in this case?

A. Yes. I have also filed a separate piece of surrebuttal testimony on RUCO's cost of capital recommendations.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains four parts: the introduction that I have just presented; a summary of AWC's rebuttal testimony; a section that addresses the operating income adjustments that are in dispute between the Company and RUCO; and a section on RUCO's surrebuttal position on the various adjustor mechanisms being proposed by the Company. My surrebuttal testimony also contains an abbreviated set of Northern Group schedules that will present RUCO's revised required revenue recommendations for each of AWC's seventeen operating systems (RUCO witness Coley's Surrebuttal testimony will include a similar set of schedules for the Company's Eastern and Western Groups).

Q. Will RUCO be filing surrebuttal testimony on rate design that takes your revised level of revenue into consideration?

A. Yes. RUCO will file surrebuttal testimony on rate design on August 12, 2009. RUCO's recommended rate design will take into account the revised level of revenue that I will be recommending in my surrebuttal testimony.

SUMMARY OF ARIZONA WATER COMPANY'S REBUTTAL TESTIMONY

Q. Have you reviewed AWC'S rebuttal testimony?

A. Yes. I have reviewed the rebuttal testimonies of Company witnesses William M. Garfield, Joseph D. Harris, Joel M. Reiker, and Fredrick K. Schneider, which were filed on July 10, 2009.

Q. Briefly summarize the rebuttal testimony of each of the aforementioned witnesses.

A. Mr. Garfield's rebuttal testimony addresses the points of disagreement that the Company has with ACC Staff and RUCO on the various adjustor mechanisms that AWC has proposed in this proceeding. Mr. Harris' rebuttal testimony focuses on the issues of water loss and the ACRM and MAP surcharges. Mr. Reiker's rebuttal testimony takes issue with a number of rate base and operating income adjustment recommendations being made by ACC Staff and RUCO. Mr. Schneider's rebuttal testimony deals with Arizona Department of Water Resources compliance, lost water, plant held for future use, and post test year plant.

Q. Which Company witnesses will your surrebuttal testimony focus on?

A. My surrebuttal testimony will focus on the issues addressed in the rebuttal testimony of Mr. Reiker, on operating income, and the rebuttal testimony of Mr. Garfield, on adjustor mechanisms.

OPERATING INCOME

Q. What operating revenue and expense adjustments are AWC and RUCO in disagreement over?

A. RUCO and AWC are in disagreement over the following three operating income adjustments: (1) RUCO's four related adjustments to normalize overtime hours that were incurred during the Test Year; (2) RUCO's reversal of a Company adjustment designed to recover revenues that may be lost as a result of implementing a conservation-oriented, three-tiered inverted block rate design for the AWC's Northern Group; and, (3) RUCO's decision to remove revenues pursuant to AWC's PPAM that is currently in effect for all five of the Company's Northern Group systems. Company Witness Joel M. Reiker also takes issue with RUCO's calculation of income tax.

Q. Does RUCO agree with Mr. Reiker's position regarding normalization of test year expenses and RUCO Operating Adjustment No.'s 1, 2, 3 and 6?

A. Yes, in part. RUCO agrees that the portion of overtime expense that was capitalized should not be included in RUCO's normalization calculation. RUCO disagrees with Mr. Reiker's other normalization arguments.

...

Q. Are the revisions to RUCO Operating Adjustments #1, 2, 3 and 6 reflected in RUCO's revised revenue figure?

A. Yes. RUCO has recalculated the aforementioned adjustments based on information obtained in the Company's response to RUCO data request 4.01. The revised adjustments are approximately one-half of the dollar amounts that were presented in direct testimony.

Q. Has RUCO revised its Operating Adjustment #4 which reversed the Company's adjustment to recover revenues that may be lost as a result of implementing a conservation-oriented, three-tiered inverted block rate design for the AWC's Northern Group?

A. No. RUCO has not revised its adjustment and has not changed its position on this issue despite the testimony of a RUCO witness that provided testimony almost two decades ago in AWC's 1991 rate case proceeding. RUCO's current position is more in line with the Commission's recent concerns regarding adjustor mechanisms and their propensity to shift risk from utilities to ratepayers. This situation was addressed in a letter by former ACC Commissioner William A. Mundell (Attachment A) which was filed in a generic docket on the investigation of regulatory and rate incentives[1].

[1] Docket Numbers E-00000J-08-0314 and G-00000C-08-0314.

Q. Is RUCO in agreement with the Company on RUCO Operating Adjustment #5, which removes revenues pursuant to AWC's PPAM that is currently in effect for all five of the Company's Northern Group systems?

A. Yes. RUCO accepts the Company's rebuttal argument on this issue, and has reversed its adjustment for the Company's Northern Group systems.

Q. Is RUCO still advocating a separate gross revenue conversion factor for each individual system?

A. No. Consistent with a prior Decision for the Company's Northern Group and RUCO's position on rate consolidation, which will be addressed in RUCO's surrebuttal testimony on rate design to be filed on August 12, 2009, RUCO is recommending a single gross revenue conversion factor for each of the Company's seventeen operating systems.

Q. Will RUCO have a final recommendation on rate case expense at the conclusion of the evidentiary hearing?

A. Yes. As noted in Mr. Reiker's rebuttal testimony, the Company is providing RUCO with updated rate case expense figures. RUCO's final recommended level of rate case expense will be presented in its final schedules.

...

Q. What increases/decreases in operating revenue is RUCO recommending as a result of the revisions to operating revenue and expense adjustments described above?

A. RUCO is recommending the following increases/decreases in operating revenue:

Eastern Group Systems	RUCO's Recommended Increase/(Decrease) In Operating Revenue	Percentage Increase/ (Decrease)
Superstition	$1,952,703	16.35%
Bisbee	$255,980	14.85%
Sierra Vista	($157,931)	(10.80%)
San Manuel	$312,445	38.46%
Oracle	($63,798)	(5.66%)
Winkleman	$20,259	20.80%
Miami	$626,319	33.84%
Total Eastern Group	**$2,945,977**	

Western Group Systems	RUCO's Recommended Increase/(Decrease) In Operating Revenue	Percentage Increase/ (Decrease)
Casa Grande	$3,487,828	31.90%
Stanfield	$143,784	108.99%
White Tank	$302,576	24.31%
Ajo	$47,989	10.19%
Coolidge	($71,427)	(3.22%)
Total Western Group	**$3,910,750**	

Western Group Systems	RUCO's Recommended Increase/(Decrease) In Operating Revenue	Percentage Increase/ (Decrease)
Lakeside	($133,634)	(5.16%)
Overgaard	($272,285)	(16.15%)
Sedona	$908,544	25.80%
Pinewood	$7,286	0.70%
Rimrock	$373,452	73.52%
Total Northern Group	**$883,363**	
Total Company	**$7,740,090**	

RUCO's recommended increase in operating revenue is $7,701,200 lower than the $15,441,290 level of increase requested by AWC. The recommendations listed above are summarized on Schedule WAR-1 for the Northern Group systems in my surrebuttal testimony and Schedule TJC-1 for the Eastern and Western Group systems that are included in the surrebuttal testimony of RUCO witness Tim Coley.

ADJUSTOR MECHANISMS

Q. Has RUCO changed its position on the various adjustor mechanisms addressed in the rebuttal testimony of Company witness William M. Garfield?

A. No. RUCO has not changed its position and continues to recommend that the Commission reject AWC's requests to restore PPAM's for the Company's Eastern and Western Groups, to continue the PPAM that is currently in place for the Company's Northern Group, to establish a PFAM

for all of the Company's operating systems (in order to pass the costs of fuel through to ratepayers), and to establish an AAM as an alternative to the aforementioned PPAM and PFAM pass through mechanisms.

Q. Please address Mr. Garfield's position that the Company-proposed AAM could be patterned on the existing ACRM, which includes an earnings test, that allows for the recovery of costs associated with meeting the requirements of the U.S. Environmental Protection Agency's ("EPA") arsenic standard?

A. RUCO has addressed this issue a number of times in the past and has not changed its position since. RUCO is opposed to ACRM-like mechanisms, such as the one being proposed by Mr. Garfield, to be used for anything other than for what it was originally intended for. The ACRM adjustor mechanism was specifically designed to address a one-time federally mandated event that impacted dozens of Arizona water companies simultaneously. The original ACRM was approved by the Commission to give water providers in Arizona the ability to recover the costs associated with meeting the EPA's revised drinking water arsenic standard of 10 parts per billion. The EPA's requirement that water providers comply with the more stringent standard was in effect an unfunded mandate from the federal government. Multiple Arizona water providers, including AWC, had no choice but to either comply with the EPA's rule or face the consequences of being in violation of it. This being the case,

representatives from the state's investor owned water companies, ACC Staff, and RUCO developed the present ACRM which allows water utilities to comply with the new EPA standard through a surcharge that was established within the context of a rate case proceeding where a constitutional finding of a utility's fair value has been established. The key point here is that the EPA's revised arsenic standard represented an extraordinary circumstance that neither Arizona's government, which includes the Commission, nor the state's water companies, either investor owned or municipal, had any control over. The AAM being proposed by Mr. Garfield has nothing in common with the circumstances that merited the approval of the ACRM. Unlike the ACRM, the AAM is not in reaction to extraordinary circumstances involving the health of Arizonans. Instead, the AAM is an attempt to pass through everyday, ordinary business expenses in order to relieve the Company from the burden of managing these fluctuating costs. In fact the implementation of such a mechanism in RUCO's view only creates a disincentive for utilities to keep costs under control because they would be able to pass them through to ratepayers. In short, the AAM is just one more way that risk is shifted from the utility to the ratepayer.

...

Q. Does RUCO have any comments on Mr. Garfield's remarks that the implementation of adjustor mechanisms, such as those proposed by the Company, would be beneficial in light of the current economic downturn resulting in budget cuts and the lack of adequate ACC Staff to handle rate cases?

A. I would submit that the implementation of adjustor mechanisms that allow the pass through of costs, without a formal rate case proceeding, could only make conditions during an economic downturn, such as the recession we are currently experiencing, only worse by facilitating increases in rates at a time when households and businesses are already struggling to make ends meet. Such pass through mechanisms would effectively shield utilities from harsh economic conditions with which their customers have to deal. The point that rate cases may take longer because of staffing shortages is an economic reality with which utilities such as AWC will just have to deal. Quite frankly, I'm somewhat disappointed that Mr. Garfield would even raise this issue given the fact that regulated monopolies such as AWC have near certain chances of surviving periods of economic distress than businesses that have to operate in a competitive environment.

...

Q. Do you have any comments regarding the NARUC and NRRI documents that Mr. Garfield presents in support of his position on adjustor mechanisms?

A. Both NARUC and NRRI state that they support the ***consideration*** of such mechanisms but not the ***adoption*** of such mechanisms. Both talk about other alternatives, such as consolidation. In light of RUCO's support of a modified consolidation plan, adjustor mechanisms are not necessary here. Moreover, the National Association of State Utility Consumer Advocates has long opposed the use of adjustor mechanisms for all of the same reasons stated by Commissioner Mundell (Attachment A), and reiterated herein (Attachment B).

Q. Does your silence on any of the issues or positions addressed in the rebuttal testimony of the Company's witnesses constitute acceptance?

A. No, it does not.

Q. Does this conclude your surrebuttal testimony on AWC?

A. Yes, it does.

ATTACHMENT A

COMMISSIONERS
MIKE GLEASON - Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

ARIZONA CORPORATION COMMISSION

Brian McNeil
Executive Director

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Direct Line: (602)542-3935
Fax (602)542-0752
E-Mail wmundell@azcc.gov

ORIGINAL

AZ CORP COMMISSION
DOCKET CONTROL

May 9, 2008

Ernest Johnson
Director, Utilities Divison
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Investigation of Regulatory & Rate Incentives for Gas & Electric Utilities;
Docket No. E-00000J-08-0314,
Docket No. G-00000C-08-0314

Dear Mr. Johnson:

As you may know, the Colorado Public Utilities Commission has opened an investigatory docket to look at incentives for gas and electric utilities under current rate-of-return regulation to see if these incentives are producing behavior consistent with the Commission's policy goals. The investigation would also examine alternative forms of regulation and explore whether alternative incentives could potentially achieve better results.

Some of the issues to be addressed in the Colorado PUC's investigation are: how adjustment clauses affect utility incentives, whether regulatory incentives could be changed to align a utility's financial incentives with energy efficient investment, and the incentives involved in competitive bidding and utilities' buy-or-build decisions.

These are questions this Commission should also consider; therefore, I request that a generic docket be opened to investigate these issues. I have attached the Colorado PUC's order so that it may serve as a template for our own inquiry into utility incentives. I particularly look forward to a discussion on adjustor mechanisms and surcharges which can increase customers' bills outside of a rate case. These have become common in recent years. This was not always the case: For example, APS did not have a power supply adjustor from 1989 to 2005 and TEP does not currently have one. Prior to the proliferation of such adjustor mechanisms and surcharges, utilities would have to bear the risk of increased fuel and purchased power costs between rate cases. With an adjustor mechanism, most of this risk is shifted to utility customers.

Given the phenomenal growth that our state has been experiencing as well as the series of rate increases that customers have had to bear, I believe that the time has come to seek creative solutions. We need to take a look at Commission policies and explore alternatives.

Thank you for your attention to this matter.

Sincerely,

William A. Mundell

William A. Mundell, Commissioner
Arizona Corporation Commission

Arizona Corporation Commission
DOCKETED
JUN 24 2008
DOCKETED BY MN

cc: Chairman Gleason
Commissioner Hatch-Miller
Commissioner Mayes
Commissioner Pierce
Brian McNeil
Janice Alward
Lyn Farmer
Rebecca Wilder

Decision No. C08-0448

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 08I-113EG

IN THE MATTER OF THE INVESTIGATION OF REGULATORY AND RATE INCENTIVES FOR GAS AND ELECTRIC UTILITIES.

ORDER OPENING INVESTIGATORY DOCKET AND NOTICE OF INQUIRY

Mailed Date: April 29, 2008
Adopted Date: March 26, 2008

I. BY THE COMMISSION

A. Statement

1. On February 21, 2008, the Commission held a deliberations meeting in which we identified and discussed a set of policy initiatives that we intend to pursue over the next year or more. One of those initiatives concerns incentives faced by the energy companies we regulate. We find that there is a need for greater understanding, by the Commission and its Staff, of the following: (1) the manner in which the existing regulatory structures and incentives influence energy utilities' behaviors; (2) the extent to which these incentives align results with Commission policy goals; (3) the manner in which alternative regulatory structures and incentives for these utilities may impact their actions; and (4) the extent to which these alternative regulatory structures may achieve results consistent with Commission policy goals.

2. As part of our deliberations on March 26, 2008, we began with a discussion of the purpose of such an investigation. We clarified that the purpose of such an investigation is to focus on utility incentives, with the goal of addressing customer-side incentives in a separate forum as part of other Commission initiatives. We also found that the scope of our investigation

should be broad enough to assess both the existing incentives for utilities inherent as part of the current regulatory paradigm (*e.g.*, rate-of-return/cost of service with varying adjustment clauses) as well as an understanding of other regulatory paradigms (*e.g.*, alternative forms of regulation, price-cap index regulation). We also discussed our vision of the process that includes participatory conversations about these issues with all stakeholders interested in these issues.

3. In addition, we discussed our expectations as to the likely outcomes of the investigation. While we cannot predict what the specific outcomes will be, possible outcomes include any or all of the following: a report from Commission Staff (Staff) summarizing the conclusions from the investigations; recommendations for rule changes; recommendations for possible legislative policy changes; and a formal record that could be included in other Commission proceedings.

4. We also discussed the priority and timing of the investigation, noting that a reasonable time for conclusion of the investigation was the end of 2008, prior to the next legislative session and contemporaneous with the expected filing of a general rate case by Public Service Company of Colorado.

5. An initial list of questions and issues were identified to assist in defining the scope of the proceeding. The questions include:

i. What basic incentives does today's regulatory structure (*e.g.*, rate-of-return regulatory structure, adjustment clauses, test year determination, depreciation policies) provide to Colorado electric and gas utilities?

ii. What are the alternatives to the Rate Base-Rate of Return model?

iii. How do adjustment clauses affect utility incentives?

iv. What are the alternatives to adjustment clauses?

v. Can the regulatory incentive structure be changed to align a utility's financial incentives with energy efficiency investment?

vi. Can the incentive structure be modified to heighten the utility's incentives for management efficiency?

vii. Should the Commission consider an electric "decoupling" mechanism?

viii. Can the regulatory incentive structure be altered to change the stakes for a utility making a build-or-buy decision?

ix. What impact does the current regulatory structure regarding the buy-or-build scenario have on competitive bidding as a tool in resource selection?

x. What is the state of the art across the nation?

The Commission understands that the outcomes of the investigation should apply prospectively, and not affect related issues that are addressed by current proceedings.

6. Additional impetus for this investigation has been provided by Governor Ritter's Executive Order D 004 08, issued on April 28, 2008. In relevant part, the Executive Order provides:

> Greenhouse Gas Emissions from the Utility Sector:
>
> I hereby request that the PUC require from each utility within its jurisdiction an ERP for achieving a 20% reduction in its greenhouse gas emissions from 2005 levels by 2020.
>
> I hereby direct GEO and the Department of Regulatory Agencies to identify regulatory and legislative changes that may be needed to provide the investor-owned utility with the appropriate incentives to reduce greenhouse gas emissions, and to reduce the financial barriers to investments in renewable energy sources, energy efficiency, carbon credits and clean coal technologies. The Executive Directors of these agencies will provide their suggestions to my office within 12 months of the date of this Executive Order.

We think that the assignment to the Department of Regulatory Agencies will be substantially assisted by our proposed investigation of utility incentives.

7. At the March 26, 2008 meeting we discussed a Staff recommendation to keep the methods used in the proceeding as flexible as possible including, but not limited to: Staff research, expert consultant research, Commission orders seeking comments, workshop presentations, and, to the extent allowable, individual discussions with parties of interest, as long as those discussions are fully disclosed to all interested parties. Since this proceeding is investigatory in nature, primarily focused on gathering information and will not impact any

current docket, the "permit, but disclose" approach is reasonable. In addition, Staff explained that the "permit, but disclose" discussions are often used by the Federal Energy Regulatory Commission and the Federal Communications Commission when investigating non-adjudicatory matters of interest before them.

8. We agree with Staff's recommendation, and direct Staff to promptly begin the research phase (both Staff research and external resource research).

9. In addition, we invite interested parties to file comments in response to this order that address the appropriate scope of this inquiry, suggesting specific topics not covered in paragraph 5 above, and methods of inquiry. We are not seeking comments on the substance of the inquiry at this point; we anticipate that the Commission will issue subsequent orders in this docket requesting replies to specific questions we pose to interested parties.

10. Once Staff has an opportunity to review comments filed by interested persons, we direct Staff to initiate a dialogue involving the Commission, Staff, and all parties in interest addressing questions related to the impact of incentives on utility decision-making; and to schedule workshops and roundtable discussions as appropriate.

II. ORDER

A. The Commission Orders That:

1. An investigatory docket is opened concerning regulatory structures and incentives that influence electric and gas utility actions under existing regulatory structures in Colorado and concerning alternative incentives and alternative regulatory and rate structures that may alter or influence utility actions.

2. Staff of the Commission shall conduct this investigation pursuant to the authority vested in the Commission pursuant to Title 40, Articles 1 through 7 of the Colorado Revised Statutes.

3. Notice of this Order shall be provided to the public and to all interested parties.

4. Interested persons are encouraged to submit comments on the scope of the proceeding within 30 days of the Mailed Date of this Order. In addition to the filing of written comments, interested persons may submit comments electronically by compact disk (CD), or e-mail to puc@dora.state.co.us.

5. This Order is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING
March 26, 2008.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

_____

_____

_____
Commissioners

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ATTACHMENT B

National Association of State Utility Consumer Advocates
RESOLUTION

Discouraging State Regulatory Commissions from Adopting Automatic Adjustment Charges for Water Company Infrastructure Costs

WHEREAS, certain regulated water companies have recently proposed mechanisms for automatically increasing water rates, prior to regulatory review, based upon isolated items of expense related to infrastructure projects; and
WHEREAS, the National Association of State Utility Consumer Advocates (NASUCA) believes that public interest is still best served by rate of return regulation of investor-owned water companies and that such automatic adjustment mechanisms contradict several sound rate of return ratemaking principles, including the matching principle, because increases to items of rate base are recognized far outside of the test year from which all other rate base, as well as revenues, expenses, and cost of capital items that are used when calculating rates, allowing 'piecemeal ratemaking' and preventing the recognition of any simultaneous offsetting reductions in other items; and

WHEREAS, automatic adjustment mechanisms also circumvent regulatory review of increases to rate base for prudence and reasonableness; and

WHEREAS, automatic adjustment mechanisms further create bad public policy by eliminating the built-in regulatory incentive to control costs between rate cases and, generates incentives to increase spending in order to avoid reduction of the surcharge which occurs if the water company's authorized return is reached; and

WHEREAS, when an automatic adjustment clause is adopted, rate stability is reduced and proper price signals are distorted by frequent rate increases, and no convincing evidence has been shown to support the claim that the frequency of rate case proceedings is reduced by such clauses; and

WHEREAS, special incentives are not needed in order ensure adequate water quality, pressure, and a proper reduction of service interruptions; and

WHEREAS, automatic adjustment mechanisms can inappropriately reward water companies that have imprudently fallen behind in infrastructure improvements; and

WHEREAS, it is inappropriate to tilt the regulatory balance against consumers and shift business risk away from water companies simply for the purpose of creating an incentive for these companies to fulfill their basic obligation to provide safe and adequate service;

THEREFORE, BE IT RESOLVED, that NASUCA strongly recommends state legislatures and state public utility commissions avoid the implementation of automatic adjustments charges for water company infrastructure costs; and

BE IT FURTHER RESOLVED, that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution. The Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Approved by NASUCA:

June, 1999, Baltimore, Maryland

Submitted By:

NASUCA Ad Hoc Water Committee

Christine Maloni Hoover, PA, Chair
Wes Blakley, IN
Robert Brabston, NJ
John Coffman, MO
Brian Gallagher, DE
Donald Rogers, MD
Dale Stransky, NV
James Warden, Jr., NY

National Association of State Utility Consumer Advocates
8380 Colesville Road, Suite 101, Silver Spring, MD 20910
Phone: (301) 589-6313 Fax: 589-6380
e-mail: nasuca@nasuca.org

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Lakeside System - Surrebuttal

TABLE OF CONTENTS TO WAR SURREBUTTAL SCHEDULES (ABBREVIATED)

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WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Lakeside System - Surrebuttal
Schedule WAR-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 7,169,218	$ 7,030,054
2	Adjusted Operating Income (Loss)	$ 517,717	$ 597,356
3	Current Rate of Return (L2 / L1)	7.22%	8.50%
4	Required Operating Income (L5 X L1)	$ 703,606	$ 515,303
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 185,889	$ (82,053)
7	Gross Revenue Conversion Factor (WAR-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 302,745	$ (133,634)
9	Adjusted Test Year Revenue	$ 2,588,849	$ 2,588,943
10	Proposed Annual Revenue (L8 + L9)	$ 2,891,594	$ 2,455,309
11	Required Percentage Increase in Revenue (L8 / L9)	11.69%	-5.16%
12	Consolidated Revenue Adjustment	$ (23,271)	$ 27,137
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ 279,355	$ (106,497)
14	Required Revenue Under Proposed Consolidation	$ 2,868,204	$ 2,482,446
15	Required Percentage Increase in Revenue Under Proposed Consolidation	10.79%	-4.11%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule WAR-2, WAR-7, and WAR-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. WAR-1, Pg 1, C (B), L4)	$ 515,303			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. WAR-1, Pg 1, C (B), L2)	597,356			
13	Required Increase In Operating Income (L11 - L12)		$ (82,053)		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 168,819			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	220,400			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ (51,581)		
17	Total Required Increase In Revenue (L13 + L16)		$ (133,634)		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. WAR-1, Pg 1, Col. (B), L12)			$ 2,455,309	
19	Operating Expense Excluding Income Tax (WAR-7, Col. (E), L27 - L22 - L23)			1,771,187	
20	Synchronized Interest (Col. (C), L37)			246,755	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 437,367	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 30,476
24	Fed. Taxable Income (L21 - L23)			$ 406,891	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ 6,250	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ 8,500	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ 91,650	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 24,443	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 138,343
31	Combined Federal and State Income Tax (L23 + L30)				$ 168,819
32	Test Year Combined Income Tax, RUCO as Adjusted (WAR-7, Col. (C), L22 + L23)				$ 220,400
33	RUCO Adjustment (L31 - L32) (See WAR-6, Col. (D), L23)				$ (51,581)
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 7,030,054	
36	Weighted Avg. Cost of Debt (Sch. WAR-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 246,755	

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Lakeside System - Surrebuttal
Schedule WAR-2

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 1,767	$ -	$ 1,767
2	Source of Supply Plant	1,730,757	(313,824)	1,416,933
3	Pumping Plant	2,184,518	-	2,184,518
4	Water Treatment Plant	72,344	-	72,344
5	Transmission & Distribution Plant	11,151,870	-	11,151,870
6	General Plant	903,362	-	903,362
7	Total Gross Plant in Service	$ 16,044,619	$ (313,824)	$ 15,730,795
8	Accumulated Depreciation	(4,088,030)	209,049	(3,878,981)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 11,956,589	$ (104,775)	$ 11,851,814
10	Advances In Aid Of Const.	$ (2,366,968)	$ -	$ (2,366,968)
11	Contribution In Aid of Const.	$ (1,691,940)	$ -	$ (1,691,940)
12	Accumulated Amortization of CIAC	370,501	-	370,501
13	NET CIAC (L5 + L6)	$ (1,321,439)	$ -	$ (1,321,439)
14	Deferred Income Tax	$ (1,188,230)	$ -	$ (1,188,230)
15	Customer Deposits	$ -	$ (8,300)	$ (8,300)
16	Allowance for Working Capital	$ 89,266	$ (26,088)	$ 63,178
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 7,169,218	$ (139,163)	$ 7,030,054

References:
Column (A): Company Schedule B-1
Column (B): Schedule WAR-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 1,767	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,767
2	Source of Supply Plant	1,730,757	-	-	(313,824)	-	-	-	1,416,933
3	Pumping Plant	2,184,518	-	-	-	-	-	-	2,184,518
4	Water Treatment Plant	72,344	-	-	-	-	-	-	72,344
5	Transmission & Distribution Plant	11,151,870	-	-	-	-	-	-	11,151,870
6	General Plant	903,362	-	-	-	-	-	-	903,362
7	Total Gross Plant in Service	$ 16,044,619	$ -	$ -	$ (313,824)	$ -	$ -	$ -	$ 15,730,795
8	Accumulated Depreciation	$ (4,088,030)	1,784	-	207,265	-	-	-	(3,878,981)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 11,956,589	$ 1,784	$ -	$ (106,559)	$ -	$ -	$ -	$ 11,851,814
10	Advances In Aid Of Const.	$ (2,366,968)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,366,968)
11	Contribution In Aid of Const.	$ (1,691,940)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,691,940)
12	Accumulated Amortization of CIAC	370,501	-	-	-	-	-	-	370,501
13	NET CIAC (L5 + L6)	$ (1,321,439)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,321,439)
14	Deferred Income Tax	$ (1,188,230)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,188,230)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (8,300)	$ -	$ (8,300)
16	Allowance for Working Capital	$ 89,266	$ -	$ -	$ -	$ -	$ -	$ (26,088)	$ 63,178
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 7,169,218	$ 1,784	$ -	$ (106,559)	$ -	$ (8,300)	$ (26,088)	$ 7,030,054

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See WAR-4 Total, WAR-4 Direct, WAR-4 PHX OFF and WAR-4 MS Schedules and WAR Tes
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Lakeside System - Surrebuttal
Schedule WAR-7

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 2,158,058	$ -	$ 2,158,058	$ (133,634)	$ 2,024,424
2	Commercial	374,740	-	374,740	-	374,740
3	Industrial	5,354	-	5,354	-	5,354
4	Private Fire Service	1,557	-	1,557	-	1,557
5	Other Water Revenues	23,656	-	23,656	-	23,656
6	Total Water Revenues	$ 2,563,364	$ -	$ 2,563,364	$ (133,634)	$ 2,429,730
7	Miscellaneous	$ 25,579	$ -	$ 25,579	$ -	$ 25,579
8	Total Operating Revenues	$ 2,588,943	$ -	$ 2,588,943	$ (133,634)	$ 2,455,309
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ 1,233	$ -	$ 1,233	$ -	$ 1,233
10	Other	5,184	-	5,184	-	5,184
11	Pumping Expenses:	-				
12	Purchased Power	181,940	-	181,940	-	181,940
13	Purchased Gas	-	-	-	-	-
14	Other	53,677	-	53,677	-	53,677
15	Water Treatment Expenses	28,463	-	28,463	-	28,463
16	Transmission & Distribution Expenses	290,447	-	290,447	-	290,447
17	Customer Accounting Expenses	275,893	-	275,893	-	275,893
18	Sales Expense	686	-	686	-	686
19	Administrative & General Expenses	506,659	(111,280)	395,379	-	395,379
20	Total Operations & Maintenance Expense	$ 1,344,181	$ (111,280)	$ 1,232,901	$ -	$ 1,232,901
21	Depreciation & Amortization Expenses	$ 416,943	$ (18,378)	$ 398,565	$ -	$ 398,565
	Taxes					
22	Federal Income Taxes	$ 129,724	$ 50,889	$ 180,613	$ (42,270)	$ 138,343
23	State Income Taxes	28,577	11,210	39,787	(9,312)	30,476
24	Property Taxes	116,684	(10,581)	106,103	-	106,103
25	Other	35,117	(1,499)	33,618	-	33,618
26	Total Taxes	$ 310,102	$ 50,019	$ 360,121	$ (51,581)	$ 308,540
27	Total Operating Expenses	$ 2,071,226	$ (79,639)	$ 1,991,587	$ (51,581)	$ 1,940,006
28	Operating Income	$ 517,717	$ 79,639	$ 597,356	$ (82,053)	$ 515,303

References:
Column (A): Company Schedule C-1
Column (B): WAR-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): WAR-1
Column (E): Column (C) + Column (D)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 2,158,058	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,158,058
2	Commercial	374,740	-	-	-	-	-	-	-	-	-	-	374,740
3	Industrial	5,354	-	-	-	-	-	-	-	-	-	-	5,354
4	Private Fire Service	1,557	-	-	-	-	-	-	-	-	-	-	1,557
5	Other Water Revenues	23,656	-	-	-	-	-	-	-	-	-	-	23,656
6	Total Water Revenues	$ 2,563,364	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,563,364
7	Miscellaneous	$ 25,579	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,579
8	Total Operating Revenues	$ 2,588,943	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,588,943
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ 1,233	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,233
10	Other	5,184	-	-	-	-	-	-	-	-	-	-	5,184
11	Pumping Expenses:		-	-	-	-	-	-	-	-	-	-	-
12	Purchased Power	181,940	-	-	-	-	-	-	-	-	-	-	181,940
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	53,677	-	-	-	-	-	-	-	-	-	-	53,677
15	Water Treatment Expenses	28,463	-	-	-	-	-	-	-	-	-	-	28,463
16	Transmission & Distribution Expenses	290,447	-	-	-	-	-	-	-	-	-	-	290,447
17	Customer Accounting Expenses	275,893	-	-	-	-	-	-	-	-	-	-	275,893
18	Sales Expense	686	-	-	-	-	-	-	-	-	-	-	686
19	Administrative & General Expenses	506,659	(9,429)	-	(766)	(96,920)	-	(33)	-	-	(4,133)	-	395,379
20	Total Operations & Maintenance Expense	$ 1,344,181	$ (9,429)	$ -	$ (766)	$ (96,920)	$ -	$ (33)	$ -	$ -	$ (4,133)	$ -	$ 1,232,901
21	Depreciation & Amortization Expenses	$ 416,943	$ -	$ -	$ -	$ -	$ -	$ -	$ (18,378)	$ -	$ -	$ -	$ 398,565
	Taxes												
22	Federal Income Taxes	$ 129,724	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50,889	$ 180,613
23	State Income Taxes	28,577	-	-	-	-	-	-	-	-	-	11,210	39,787
24	Property Taxes	116,684	-	-	-	-	-	-	-	(10,581)	-	-	106,103
25	Other	35,117	-	(1,499)	-	-	-	-	-	-	-	-	33,618
26	Total Taxes	$ 310,102	$ -	$ (1,499)	$ -	$ -	$ -	$ -	$ -	$ (10,581)	$ -	$ 62,099	$ 360,121
27	Total Operating Expenses	$ 2,071,226	$ (9,429)	$ (1,499)	$ (766)	$ (96,920)	$ -	$ (33)	$ (18,378)	$ (10,581)	$ (4,133)	$ 62,099	$ 1,991,587
28	Operating Income	$ 517,717	$ 9,429	$ 1,499	$ 766	$ 96,920	$ -	$ 33	$ 18,378	$ 10,581	$ 4,133	$ (62,099)	$ 597,356

ADJUSTMENTS:
1 - Labor Expense - Normalize OT Hours in Test Year
2 - Payroll Tax Expense Related to Adjustment 1
3 - 401(K) Expense Related to Adjustment 1
4 - Reverse Adjustment for Conservation
5 - Purchased Power Revenues
6 - Insurance Expense
7 - Depreciation Expense
8 - Property Tax Expense
9 - Rate Case Expense
10 - Income Tax

REFERENCE:
Testimony, WAR And Schedule WAR-9 Page, 1 of 3
Testimony, WAR And Schedule WAR-9 Page, 2 of 3
Testimony, WAR And Schedule WAR-9 Page, 3 of 3
Testimony WAR
Testimony WAR
Testimony, WAR And Schedule WAR-10
Testimony, WAR And Schedule WAR-11
Testimony, WAR And Schedule WAR-12
Testimony, WAR And Schedule WAR-13
Testimony, WAR And Schedule WAR-14

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

TABLE OF CONTENTS TO WAR SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

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Overgaard System - Surrebuttal
Schedule WAR-1
Page 1 of 1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 3,338,584	$ 3,318,815
2	Adjusted Operating Income (Loss)	$ 369,890	$ 410,455
3	Current Rate of Return (L2 / L1)	11.08%	12.37%
4	Required Operating Income (L5 X L1)	$ 327,657	$ 243,269
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ (42,232)	$ (167,186)
7	Gross Revenue Conversion Factor (WAR-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ (68,781)	$ (272,285)
9	Adjusted Test Year Revenue	$ 1,686,342	$ 1,686,342
10	Proposed Annual Revenue (L8 + L9)	$ 1,617,561	$ 1,414,057
11	Required Percentage Increase in Revenue (L8 / L9)	-4.08%	-16.15%
12	Consolidated Revenue Adjustment	$ 23,271	$ 21,775
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ (45,030)	$ (250,510)
14	Required Revenue Under Proposed Consolidation	$ 1,640,619	$ 1,435,832
15	Required Percentage Increase in Revenue Under Proposed Consolidation	-2.67%	-14.86%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule WAR-2, WAR-7, and WAR-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. WAR-1, Pg 1, C (B), L4)	$ 243,269			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. WAR-1, Pg 1, C (B), L2)	410,455			
13	Required Increase In Operating Income (L11 - L12)		$ (167,186)		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 79,698			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	184,797			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ (105,099)		
17	Total Required Increase In Revenue (L13 + L16)		$ (272,285)		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. WAR-1, Pg 1, Col. (B), L12)			$ 1,414,057	
19	Operating Expense Excluding Income Tax (WAR-7, Col. (E), L27 - L22 - L23)			1,091,090	
20	Synchronized Interest (Col. (C), L37)			116,490	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 206,476	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 14,387
24	Fed. Taxable Income (L21 - L23)			$ 192,089	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 65,310	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 65,310
31	Combined Federal and State Income Tax (L23 + L30)				$ 79,698
32	Test Year Combined Income Tax, RUCO as Adjusted (WAR-7, Col. (C), L22 + L23)				$ 184,797
33	RUCO Adjustment (L31 - L32) (See WAR-6, Col. (D), L23)				$ (105,099)
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 3,318,815	
36	Weighted Avg. Cost of Debt (Sch. WAR-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 116,490	

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Overgaard System - Surrebuttal
Schedule WAR-2

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 1,111	$ -	$ 1,111
2	Source of Supply Plant	709,152	-	709,152
3	Pumping Plant	588,420	-	588,420
4	Water Treatment Plant	58,991	-	58,991
5	Transmission & Distribution Plant	8,818,945	-	8,818,945
6	General Plant	728,787	-	728,787
7	Total Gross Plant in Service	$ 10,905,405	$ -	$ 10,905,405
8	Accumulated Depreciation	(3,542,894)	629	(3,542,265)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 7,362,511	$ 629	$ 7,363,140
10	Advances In Aid Of Const.	$ (1,420,695)	$ -	$ (1,420,695)
11	Contribution In Aid of Const.	$ (2,543,592)	$ -	$ (2,543,592)
12	Accumulated Amortization of CIAC	613,170	-	613,170
13	NET CIAC (L5 + L6)	$ (1,930,422)	$ -	$ (1,930,422)
14	Deferred Income Tax	$ (764,684)	$ -	$ (764,684)
15	Customer Deposits	$ -	$ (6,935)	$ (6,935)
16	Allowance for Working Capital	$ 91,873	$ (13,463)	$ 78,411
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 3,338,584	$ (19,768)	$ 3,318,815

References:
Column (A): Company Schedule B-1
Column (B): Schedule WAR-3
Column (C): Column (A) + Column (B)

Arizona Water Company
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Test Year Ended December 31, 2007

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 1,111	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,111
2	Source of Supply Plant	709,152	-	-	-	-	-	-	709,152
3	Pumping Plant	588,420	-	-	-	-	-	-	588,420
4	Water Treatment Plant	58,991	-	-	-	-	-	-	58,991
5	Transmission & Distribution Plant	8,818,945	-	-	-	-	-	-	8,818,945
6	General Plant	728,787	-	-	-	-	-	-	728,787
7	Total Gross Plant in Service	$ 10,905,405	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,905,405
8	Accumulated Depreciation	$ (3,542,894)	629	-	-	-	-	-	(3,542,265)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 7,362,511	$ 629	$ -	$ -	$ -	$ -	$ -	$ 7,363,140
10	Advances In Aid Of Const.	$ (1,420,695)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,420,695)
11	Contribution In Aid of Const.	$ (2,543,592)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,543,592)
12	Accumulated Amortization of CIAC	613,170	-	-	-	-	-	-	613,170
13	NET CIAC (L5 + L6)	$ (1,930,422)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,930,422)
14	Deferred Income Tax	$ (764,684)	$ -	$ -	$ -	$ -	$ -	$ -	$ (764,684)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (6,935)	$ -	$ (6,935)
16	Allowance for Working Capital	$ 91,873	$ -	$ -	$ -	$ -	$ -	$ (13,463)	$ 78,411
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 3,338,584	$ 629	$ -	$ -	$ -	$ (6,935)	$ (13,463)	$ 3,318,815

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See WAR-4 Total, WAR-4 Direct, WAR-4 PHX OFF and WAR-4 MS Schedules and WAR Tes
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

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Overgaard System - Surrebuttal
Schedule WAR-7

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 1,521,187	$ -	$ 1,521,187	$ (272,285)	$ 1,248,902
2	Commercial	129,575	-	129,575	-	129,575
3	Industrial	-	-	-	-	-
4	Private Fire Service	1,195	-	1,195	-	1,195
5	Other Water Revenues	9,963	-	9,963	-	9,963
6	Total Water Revenues	$ 1,661,920	$ -	$ 1,661,920	$ (272,285)	$ 1,389,635
7	Miscellaneous	$ 24,422	$ -	$ 24,422	$ -	$ 24,422
8	Total Operating Revenues	$ 1,686,342	$ -	$ 1,686,342	$ (272,285)	$ 1,414,057
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ 58	$ -	$ 58	$ -	$ 58
10	Other	4,378	-	4,378	-	4,378
11	Pumping Expenses:	-				
12	Purchased Power	71,171	-	71,171	-	71,171
13	Purchased Gas	-	-	-	-	-
14	Other	43,941	-	43,941	-	43,941
15	Water Treatment Expenses	14,733	-	14,733	-	14,733
16	Transmission & Distribution Expenses	237,473	-	237,473	-	237,473
17	Customer Accounting Expenses	207,198	-	207,198	-	207,198
18	Sales Expense	446	-	446	-	446
19	Administrative & General Expenses	279,673	(61,225)	218,449	-	218,449
20	Total Operations & Maintenance Expense	$ 859,072	$ (61,225)	$ 797,848	$ -	$ 797,848
21	Depreciation & Amortization Expenses	$ 214,780	$ (3,477)	$ 211,304	$ -	$ 211,304
	Taxes					
22	Federal Income Taxes	$ 126,761	$ 24,676	$ 151,437	$ (86,126)	$ 65,310
23	State Income Taxes	27,924	5,436	33,360	(18,973)	14,387
24	Property Taxes	65,159	(5,012)	60,147	-	60,147
25	Other	22,756	(965)	21,791	-	21,791
26	Total Taxes	$ 242,600	$ 24,135	$ 266,735	$ (105,099)	$ 161,636
27	Total Operating Expenses	$ 1,316,453	$ (40,566)	$ 1,275,887	$ (105,099)	$ 1,170,788
28	Operating Income	$ 369,890	$ 40,566	$ 410,455	$ (167,186)	$ 243,269

References:
Column (A): Company Schedule C-1
Column (B): WAR-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): WAR-1
Column (E): Column (C) + Column (D)

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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 1,521,187	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,521,187
2	Commercial	129,575	-	-	-	-	-	-	-	-	-	-	129,575
3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-
4	Private Fire Service	1,195	-	-	-	-	-	-	-	-	-	-	1,195
5	Other Water Revenues	9,963	-	-	-	-	-	-	-	-	-	-	9,963
6	Total Water Revenues	$ 1,661,920	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,661,920
7	Miscellaneous	$ 24,422	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,422
8	Total Operating Revenues	$ 1,686,342	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,686,342
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ 58	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 58
10	Other	4,378	-	-	-	-	-	-	-	-	-	-	4,378
11	Pumping Expenses:		-	-	-	-	-	-	-	-	-	-	-
12	Purchased Power	71,171	-	-	-	-	-	-	-	-	-	-	71,171
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	43,941	-	-	-	-	-	-	-	-	-	-	43,941
15	Water Treatment Expenses	14,733	-	-	-	-	-	-	-	-	-	-	14,733
16	Transmission & Distribution Expenses	237,473	-	-	-	-	-	-	-	-	-	-	237,473
17	Customer Accounting Expenses	207,198	-	-	-	-	-	-	-	-	-	-	207,198
18	Sales Expense	446	-	-	-	-	-	-	-	-	-	-	446
19	Administrative & General Expenses	279,673	(6,068)	-	(493)	(51,977)	-	(28)	-	-	(2,660)	-	218,449
20	Total Operations & Maintenance Expense	$ 859,072	$ (6,068)	$ -	$ (493)	$ (51,977)	$ -	$ (28)	$ -	$ -	$ (2,660)	$ -	$ 797,848
21	Depreciation & Amortization Expenses	$ 214,780	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,477)	$ -	$ -	$ -	$ 211,304
	Taxes												
22	Federal Income Taxes	$ 126,761	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,676	$ 151,437
23	State Income Taxes	27,924	-	-	-	-	-	-	-	-	-	5,436	33,360
24	Property Taxes	65,159	-	-	-	-	-	-	-	(5,012)	-	-	60,147
25	Other	22,756	-	(965)	-	-	-	-	-	-	-	-	21,791
26	Total Taxes	$ 242,600	$ -	$ (965)	$ -	$ -	$ -	$ -	$ -	$ (5,012)	$ -	$ 30,112	$ 266,735
27	Total Operating Expenses	$ 1,316,453	$ (6,068)	$ (965)	$ (493)	$ (51,977)	$ -	$ (28)	$ (3,477)	$ (5,012)	$ (2,660)	$ 30,112	$ 1,275,887
28	Operating Income	$ 369,890	$ 6,068	$ 965	$ 493	$ 51,977	$ -	$ 28	$ 3,477	$ 5,012	$ 2,660	$ (30,112)	$ 410,455

ADJUSTMENTS:
1 - Labor Expense - Normalize OT Hours in Test Year
2 - Payroll Tax Expense Related to Adjustment 1
3 - 401(K) Expense Related to Adjustment 1
4 - Reverse Adjustment for Conservation
5 - Purchased Power Revenues
6 - Insurance Expense
7 - Depreciation Expense
8 - Property Tax Expense
9 - Rate Case Expense
10 - Income Tax

REFERENCE:
Testimony, WAR And Schedule WAR-9 Page, 1 of 3
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Testimony, WAR And Schedule WAR-12
Testimony, WAR And Schedule WAR-13
Testimony, WAR And Schedule WAR-14

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Overgaard System - Surrebuttal
Schedule WAR-15

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

TABLE OF CONTENTS TO WAR SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

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Sedona System - Surrebuttual
Schedule WAR-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 18,018,530	$ 14,833,726
2	Adjusted Operating Income (Loss)	$ 424,708	$ 529,456
3	Current Rate of Return (L2 / L1)	2.36%	3.57%
4	Required Operating Income (L5 X L1)	$ 1,768,386	$ 1,087,312
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 1,343,679	$ 557,856
7	Gross Revenue Conversion Factor (WAR-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 2,188,362	$ 908,544
9	Adjusted Test Year Revenue	$ 3,521,124	$ 3,521,124
10	Proposed Annual Revenue (L8 + L9)	$ 5,709,486	$ 4,429,669
11	Required Percentage Increase in Revenue (L8 / L9)	62.15%	25.80%
12	Consolidated Revenue Adjustment	$ 216,885	$ 44,421
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ 2,404,707	$ 952,966
14	Required Revenue Under Proposed Consolidation	$ 5,926,065	$ 4,474,090
15	Required Percentage Increase in Revenue Under Proposed Consolidation	68.29%	27.06%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule WAR-2, WAR-7, and WAR-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. WAR-1, Pg 1, C (B), L4)	$ 1,087,312			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. WAR-1, Pg 1, C (B), L2)	529,456			
13	Required Increase In Operating Income (L11 - L12)		$ 557,856		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 356,215			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	5,527			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 350,688		
17	Total Required Increase In Revenue (L13 + L16)		$ 908,544		
				RUCO Recommended	
	CALCULATION OF INCOME TAX:				
18	Revenue (Sch. WAR-1, Pg 1, Col. (B), L12)			$ 4,429,669	
19	Operating Expense Excluding Income Tax (WAR-7, Col. (E), L27 - L22 - L23)			2,986,142	
20	Synchronized Interest (Col. (C), L37)			520,664	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 922,863	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 64,305
24	Fed. Taxable Income (L21 - L23)			$ 858,558	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 291,910	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 291,910
31	Combined Federal and State Income Tax (L23 + L30)				$ 356,215
32	Test Year Combined Income Tax, RUCO as Adjusted (WAR-7, Col. (C), L22 + L23)				$ 5,527
33	RUCO Adjustment (L31 - L32) (See WAR-6, Col. (D), L23)				$ 350,688
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 14,833,726	
36	Weighted Avg. Cost of Debt (Sch. WAR-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 520,664	

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Sedona System - Surrebuttual
Schedule WAR-2
Page 1 of 1

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 3,287	$ -	$ 3,287
2	Source of Supply Plant	5,917,390	(3,397,718)	2,519,672
3	Pumping Plant	2,266,429	(6,761)	2,259,668
4	Water Treatment Plant	1,297,124	-	1,297,124
5	Transmission & Distribution Plant	23,674,185	(661,738)	23,012,447
6	General Plant	1,166,200	-	1,166,200
7	Total Gross Plant in Service	$ 34,324,616	$ (4,066,217)	$ 30,258,399
8	Accumulated Depreciation	(6,146,140)	948,993	(5,197,147)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 28,178,476	$ (3,117,224)	$ 25,061,252
10	Advances In Aid Of Const.	$ (3,651,412)	$ -	$ (3,651,412)
11	Contribution In Aid of Const.	$ (6,396,542)	$ -	$ (6,396,542)
12	Accumulated Amortization of CIAC	1,279,254	-	1,279,254
13	NET CIAC (L5 + L6)	$ (5,117,288)	$ -	$ (5,117,288)
14	Deferred Income Tax	$ (1,619,443)	$ -	$ (1,619,443)
15	Customer Deposits	$ -	$ (18,576)	$ (18,576)
16	Allowance for Working Capital	$ 228,197	$ (49,005)	$ 179,193
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 18,018,530	$ (3,184,804)	$ 14,833,726

References:
Column (A): Company Schedule B-1
Column (B): Schedule WAR-3
Column (C): Column (A) + Column (B)

Arizona Water Company
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Sedona System - Surrebuttual
Schedule WAR-3

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4 REMOVE PTY PLANT 11.16	(F) ADJMT NO. 5 REMOVE PTY PLANT	(G) ADJMT NO. 6 CUSTOMER DEPOSITS	(H) ADJMT NO. 7 WORKING CAPITAL	(I) RUCO ADJ'TED OCRB/FVRB
	Plant Classification									
1	Intangible Plant	$ 3,287	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,287
2	Source of Supply Plant	5,917,390	-	-	(1,386,142)	(2,011,576)	-	-	-	2,519,672
3	Pumping Plant	2,266,429	-	-	(6,761)	-	-	-	-	2,259,668
4	Water Treatment Plant	1,297,124	-	-	-	-	-	-	-	1,297,124
5	Transmission & Distribution Plant	23,674,185	-	-	-	-	(661,738)	-	-	23,012,447
6	General Plant	1,166,200	-	-	-	-	-	-	-	1,166,200
7	Total Gross Plant in Service	$ 34,324,616	$ -	$ -	$ (1,392,903)	$ (2,011,576)	$ (661,738)	$ -	$ -	$ 30,258,399
8	Accumulated Depreciation	(6,146,140)	(4,975)	-	926,106	21,940	5,923	-	-	(5,197,147)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 28,178,476	$ (4,975)	$ -	$ (466,797)	$ (1,989,636)	$ (655,815)	$ -	$ -	$ 25,061,252
10	Advances In Aid Of Const.	$ (3,651,412)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,651,412)
11	Contribution In Aid of Const.	$ (6,396,542)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,396,542)
12	Accumulated Amortization of CIAC	1,279,254	-	-	-	-	-	-	-	1,279,254
13	NET CIAC (L5 + L6)	$ (5,117,288)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,117,288)
14	Deferred Income Tax	$ (1,619,443)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,619,443)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ -	$ (18,576)	$ -	$ (18,576)
16	Allowance for Working Capital	$ 228,197	$ -	$ -	$ -	$ -	$ -	$ -	$ (49,005)	$ 179,193
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 18,018,530	$ (4,975)	$ -	$ (466,797)	$ (1,989,636)	$ (655,815)	$ (18,576)	$ (49,005)	$ 14,833,726

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See WAR-4 Total, WAR-4 Direct, WAR-4 PHX OFF and WAR-4 MS Schedules and WAR Testimony)
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - To Remove Post Test Year Plant Included in Rate Application
Column (F): Adjustment No. 5 - ADOT Post Test Year Project
Column (G): Adjustment No. 6 - Customer Deposits
Column (H): Adjustment No. 7 - Working Capital

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Sedona System - Surrebuttual
Schedule WAR-7

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 2,500,263	$ -	$ 2,500,263	$ 908,544	$ 3,408,808
2	Commercial	957,571	-	957,571	-	957,571
3	Industrial	315	-	315	-	315
4	Private Fire Service	7,692	-	7,692	-	7,692
5	Other Water Revenues	26,716	-	26,716	-	26,716
6	Total Water Revenues	$ 3,492,558	$ -	$ 3,492,558	$ 908,544	$ 4,401,102
7	Miscellaneous	$ 28,567	$ -	$ 28,567	$ -	$ 28,567
8	Total Operating Revenues	$ 3,521,124	$ -	$ 3,521,124	$ 908,544	$ 4,429,669
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	7,247	-	7,247	-	7,247
11	Pumping Expenses:	-				
12	Purchased Power	518,834	-	518,834	-	518,834
13	Purchased Gas	2,626	-	2,626	-	2,626
14	Other	129,182	-	129,182	-	129,182
15	Water Treatment Expenses	319,722	-	319,722	-	319,722
16	Transmission & Distribution Expenses	400,194	-	400,194	-	400,194
17	Customer Accounting Expenses	323,108	-	323,108	-	323,108
18	Sales Expense	2,838	-	2,838	-	2,838
19	Administrative & General Expenses	641,077	(131,202)	509,874	-	509,874
20	Total Operations & Maintenance Expense	$ 2,344,827	$ (131,202)	$ 2,213,624	$ -	$ 2,213,624
21	Depreciation & Amortization Expenses	$ 731,033	$ (117,285)	$ 613,748	$ -	$ 613,748
	Taxes					
22	Federal Income Taxes	$ (125,482)	$ 130,011	$ 4,529	$ 287,381	$ 291,910
23	State Income Taxes	(27,643)	28,640	998	63,307	64,305
24	Property Taxes	125,837	(12,869)	112,968	-	112,968
25	Other	47,845	(2,043)	45,802	-	45,802
26	Total Taxes	$ 20,557	$ 143,739	$ 164,296	$ 350,688	$ 514,984
27	Total Operating Expenses	$ 3,096,417	$ (104,748)	$ 2,991,669	$ 350,688	$ 3,342,357
28	Operating Income	$ 424,708	$ 104,748	$ 529,456	$ 557,856	$ 1,087,312

References:
Column (A): Company Schedule C-1
Column (B): WAR-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): WAR-1
Column (E): Column (C) + Column (D)

Arizona Water Company
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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 2,500,263	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,500,263
2	Commercial	957,571	-	-	-	-	-	-	-	-	-	-	957,571
3	Industrial	315	-	-	-	-	-	-	-	-	-	-	315
4	Private Fire Service	7,692	-	-	-	-	-	-	-	-	-	-	7,692
5	Other Water Revenues	26,716	-	-	-	-	-	-	-	-	-	-	26,716
6	Total Water Revenues	$ 3,492,558	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,492,558
7	Miscellaneous	$ 28,567	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,567
8	Total Operating Revenues	$ 3,521,124	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,521,124
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	7,247	-	-	-	-	-	-	-	-	-	-	7,247
11	Pumping Expenses:					-							
12	Purchased Power	518,834	-	-	-	-	-	-	-	-	-	-	518,834
13	Purchased Gas	2,626	-	-	-	-	-	-	-	-	-	-	2,626
14	Other	129,182	-	-	-	-	-	-	-	-	-	-	129,182
15	Water Treatment Expenses	319,722	-	-	-	-	-	-	-	-	-	-	319,722
16	Transmission & Distribution Expenses	400,194	-	-	-	-	-	-	-	-	-	-	400,194
17	Customer Accounting Expenses	323,108	-	-	-	-	-	-	-	-	-	-	323,108
18	Sales Expense	2,838	-	-	-	-	-	-	-	-	-	-	2,838
19	Administrative & General Expenses	641,077	(12,850)	-	(1,043)	(111,634)	-	(42)	-	-	(5,633)	-	509,874
20	Total Operations & Maintenance Expense	$ 2,344,827	$ (12,850)	$ -	$ (1,043)	$ (111,634)	$ -	$ (42)	$ -	$ -	$ (5,633)	$ -	$ 2,213,624
21	Depreciation & Amortization Expenses	$ 731,033	$ -	$ -	$ -	$ -	$ -	$ -	$ (117,285)	$ -	$ -	$ -	$ 613,748
	Taxes												
22	Federal Income Taxes	$ (125,482)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 130,011	$ 4,529
23	State Income Taxes	(27,643)	-	-	-	-	-	-	-	-	-	28,640	998
24	Property Taxes	125,837	-	-	-	-	-	-	-	(12,869)	-	-	112,968
25	Other	47,845	-	(2,043)	-	-	-	-	-	-	-	-	45,802
26	Total Taxes	$ 20,557	$ -	$ (2,043)	$ -	$ -	$ -	$ -	$ -	$ (12,869)	$ -	$ 158,652	$ 164,296
27	Total Operating Expenses	$ 3,096,417	$ (12,850)	$ (2,043)	$ (1,043)	$ (111,634)	$ -	$ (42)	$ (117,285)	$ (12,869)	$ (5,633)	$ 158,652	$ 2,991,669
28	Operating Income	$ 424,708	$ 12,850	$ 2,043	$ 1,043	$ 111,634	$ -	$ 42	$ 117,285	$ 12,869	$ 5,633	$ (158,652)	$ 529,456

ADJUSTMENTS:
1 - Labor Expense - Normalize OT Hours in Test Year
2 - Payroll Tax Expense Related to Adjustment 1
3 - 401(K) Expense Related to Adjustment 1
4 - Reverse Adjustment for Conservation
5 - Purchased Power Revenues
6 - Insurance Expense
7 - Depreciation Expense
8 - Property Tax Expense
9 - Rate Case Expense
10 - Income Tax

REFERENCE:
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Testimony, WAR And Schedule WAR-14

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Sedona System - Surrebuttual
Schedule WAR-15

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

TABLE OF CONTENTS TO WAR SURREBUTTAL SCHEDULES (ABBREVIATED)

SCH. NO.	PAGE NO.	TITLE
WAR-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
WAR-2	1	RATE BASE
WAR-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
WAR-7	1	OPERATING INCOME
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WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 1,882,836	$ 1,830,266
2	Adjusted Operating Income (Loss)	$ 104,677	$ 129,685
3	Current Rate of Return (L2 / L1)	5.56%	7.09%
4	Required Operating Income (L5 X L1)	$ 184,787	$ 134,158
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 80,110	$ 4,474
7	Gross Revenue Conversion Factor (WAR-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 130,470	$ 7,286
9	Adjusted Test Year Revenue	$ 1,047,463	$ 1,047,463
10	Proposed Annual Revenue (L8 + L9)	$ 1,177,933	$ 1,054,749
11	Required Percentage Increase in Revenue (L8 / L9)	12.46%	0.70%
12	Consolidated Revenue Adjustment	$ 6,107	$ 14,494
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ 136,993	$ 21,781
14	Required Revenue Under Proposed Consolidation	$ 1,183,734	$ 1,069,244
15	Required Percentage Increase in Revenue Under Proposed Consolidation	13.09%	2.08%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule WAR-2, WAR-7, and WAR-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. WAR-1, Pg 1, C (B), L4)	$ 134,158			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. WAR-1, Pg 1, C (B), L2)	129,685			
13	Required Increase In Operating Income (L11 - L12)		$ 4,474		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 43,952			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	41,139			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 2,812		
17	Total Required Increase In Revenue (L13 + L16)		$ 7,286		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. WAR-1, Pg 1, Col. (B), L12)			$ 1,054,749	
19	Operating Expense Excluding Income Tax (WAR-7, Col. (E), L27 - L22 - L23)			876,639	
20	Synchronized Interest (Col. (C), L37)			64,242	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 113,868	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 7,934
24	Fed. Taxable Income (L21 - L23)			$ 105,934	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 36,017	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 36,017
31	Combined Federal and State Income Tax (L23 + L30)				$ 43,952
32	Test Year Combined Income Tax, RUCO as Adjusted (WAR-7, Col. (C), L22 + L23)				$ 41,139
33	RUCO Adjustment (L31 - L32) (See WAR-6, Col. (D), L23)				$ 2,812
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 1,830,266	
36	Weighted Avg. Cost of Debt (Sch. WAR-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 64,242	

Arizona Water Company
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Pinewood System - Surrebuttal
Schedule WAR-2
Page 1 of 1

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 863	$ -	$ 863
2	Source of Supply Plant	1,146,589	(13,512)	1,133,076
3	Pumping Plant	471,603	(40,464)	431,139
4	Water Treatment Plant	32,915	-	32,915
5	Transmission & Distribution Plant	3,563,550	(89)	3,563,461
6	General Plant	239,448	-	239,448
7	Total Gross Plant in Service	$ 5,454,969	$ (54,065)	$ 5,400,904
8	Accumulated Depreciation	(2,349,271)	12,361	(2,336,910)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 3,105,698	$ (41,704)	$ 3,063,994
10	Advances In Aid Of Const.	$ (249,075)	$ -	$ (249,075)
11	Contribution In Aid of Const.	$ (783,751)	$ -	$ (783,751)
12	Accumulated Amortization of CIAC	$ 296,411	-	296,411
13	NET CIAC (L5 + L6)	$ (487,340)	$ -	$ (487,340)
14	Deferred Income Tax	$ (565,368)	$ -	$ (565,368)
15	Customer Deposits	$ -	$ (4,330)	$ (4,330)
16	Allowance for Working Capital	$ 78,921	$ (6,536)	$ 72,385
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 1,882,836	$ (52,571)	$ 1,830,266

References:
Column (A): Company Schedule B-1
Column (B): Schedule WAR-3
Column (C): Column (A) + Column (B)

Arizona Water Company
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Test Year Ended December 31, 2007

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4 REMOVE PTY PLANT	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 863	$ -	$ -	$ -	$ -	$ -	$ -	$ 863
2	Source of Supply Plant	1,146,589	-	-	(13,512)	-	-	-	1,133,076
3	Pumping Plant	471,603	-	-	-	(40,464)	-	-	431,139
4	Water Treatment Plant	32,915	-	-	-	-	-	-	32,915
5	Transmission & Distribution Plant	3,563,550	-	-	-	(89)	-	-	3,563,461
6	General Plant	239,448	-	-	-	-	-	-	239,448
7	Total Gross Plant in Service	$ 5,454,969	$ -	$ -	$ (13,512)	$ (40,553)	$ -	$ -	$ 5,400,904
8	Accumulated Depreciation	(2,349,271)	496	-	10,674	1,191	-	-	(2,336,910)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 3,105,698	$ 496	$ -	$ (2,838)	$ (39,362)	$ -	$ -	$ 3,063,994
10	Advances In Aid Of Const.	$ (249,075)	$ -	$ -	$ -	$ -	$ -	$ -	$ (249,075)
11	Contribution In Aid of Const.	$ (783,751)	$ -	$ -	$ -	$ -	$ -	$ -	$ (783,751)
12	Accumulated Amortization of CIAC	296,411	-	-	-	-	-	-	296,411
13	NET CIAC (L5 + L6)	$ (487,340)	$ -	$ -	$ -	$ -	$ -	$ -	$ (487,340)
14	Deferred Income Tax	$ (565,368)	$ -	$ -	$ -	$ -	$ -	$ -	$ (565,368)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (4,330)	$ -	$ (4,330)
16	Allowance for Working Capital	78,921	$ -	$ -	$ -	$ -	$ -	$ (6,536)	$ 72,385
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 1,882,836	$ 496	$ -	$ (2,838)	$ (39,362)	$ (4,330)	$ (6,536)	$ 1,830,266

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See WAR-4 Total, WAR-4 Direct, WAR-4 PHX OFF and WAR-4 MS Schedules and WAR Tes
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Remove Company PTY Plant Adjustment JMR-1
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 1,015,253	$ -	$ 1,015,253	$ 7,286	$ 1,022,539
2	Commercial	22,880	-	22,880	-	22,880
3	Industrial	507	-	507	-	507
4	Private Fire Service	179	-	179	-	179
5	Other Water Revenues	1,784	-	1,784	-	1,784
6	Total Water Revenues	$ 1,040,604	$ -	$ 1,040,604	$ 7,286	$ 1,047,890
7	Miscellaneous	$ 6,859	$ -	$ 6,859	$ -	$ 6,859
8	Total Operating Revenues	$ 1,047,463	$ -	$ 1,047,463	$ 7,286	$ 1,054,749
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	3,239	-	3,239	-	3,239
11	Pumping Expenses:	-				
12	Purchased Power	84,846	-	84,846	-	84,846
13	Purchased Gas	-	-	-	-	-
14	Other	56,303	-	56,303	-	56,303
15	Water Treatment Expenses	33,840	-	33,840	-	33,840
16	Transmission & Distribution Expenses	173,376	-	173,376	-	173,376
17	Customer Accounting Expenses	133,433	-	133,433	-	133,433
18	Sales Expense	1,188	-	1,188	-	1,188
19	Administrative & General Expenses	243,746	(35,187)	208,559	-	208,559
20	Total Operations & Maintenance Expense	$ 729,970	$ (35,187)	$ 694,782	$ -	$ 694,782
21	Depreciation & Amortization Expenses	$ 132,206	$ (5,405)	$ 126,801	$ -	$ 126,801
	Taxes					
22	Federal Income Taxes	$ 17,950	$ 15,763	$ 33,713	$ 2,305	$ 36,017
23	State Income Taxes	3,954	3,472	7,427	508	7,934
24	Property Taxes	41,350	(2,938)	38,412	-	38,412
25	Other	17,357	(713)	16,644	-	16,644
26	Total Taxes	$ 80,611	$ 15,584	$ 96,195	$ 2,812	$ 99,007
27	Total Operating Expenses	$ 942,787	$ (25,008)	$ 917,779	$ 2,812	$ 920,591
28	Operating Income	$ 104,677	$ 25,008	$ 129,685	$ 4,474	$ 134,158

References:
Column (A): Company Schedule C-1
Column (B): WAR-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): WAR-1
Column (E): Column (C) + Column (D)

Arizona Water Company
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Test Year Ended December 31, 2007

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 1,015,253	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,015,253
2	Commercial	22,880	-	-	-	-	-	-	-	-	-	-	22,880
3	Industrial	507	-	-	-	-	-	-	-	-	-	-	507
4	Private Fire Service	179	-	-	-	-	-	-	-	-	-	-	179
5	Other Water Revenues	1,784	-	-	-	-	-	-	-	-	-	-	1,784
6	Total Water Revenues	$ 1,040,604	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,040,604
7	Miscellaneous	$ 6,859	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,859
8	Total Operating Revenues	$ 1,047,463	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,047,463
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	3,239	-	-	-	-	-	-	-	-	-	-	3,239
11	Pumping Expenses:												
12	Purchased Power	84,846	-	-	-	-	-	-	-	-	-	-	84,846
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	56,303	-	-	-	-	-	-	-	-	-	-	56,303
15	Water Treatment Expenses	33,840	-	-	-	-	-	-	-	-	-	-	33,840
16	Transmission & Distribution Expenses	173,376	-	-	-	-	-	-	-	-	-	-	173,376
17	Customer Accounting Expenses	133,433	-	-	-	-	-	-	-	-	-	-	133,433
18	Sales Expense	1,188	-	-	-	-	-	-	-	-	-	-	1,188
19	Administrative & General Expenses	243,746	(4,486)	-	(364)	(28,351)	-	(19)	-	-	(1,967)	-	208,559
20	Total Operations & Maintenance Expense	$ 729,970	$ (4,486)	$ -	$ (364)	$ (28,351)	$ -	$ (19)	$ -	$ -	$ (1,967)	$ -	$ 694,782
21	Depreciation & Amortization Expenses	$ 132,206	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,405)	$ -	$ -	$ -	$ 126,801
	Taxes												
22	Federal Income Taxes	$ 17,950	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,763	$ 33,713
23	State Income Taxes	3,954	-	-	-	-	-	-	-	-	-	3,472	7,427
24	Property Taxes	41,350	-	-	-	-	-	-	-	(2,938)	-	-	38,412
25	Other	17,357	-	(713)	-	-	-	-	-	-	-	-	16,644
26	Total Taxes	$ 80,611	$ -	$ (713)	$ -	$ -	$ -	$ -	$ -	$ (2,938)	$ -	$ 19,235	$ 96,195
27	Total Operating Expenses	$ 942,787	$ (4,486)	$ (713)	$ (364)	$ (28,351)	$ -	$ (19)	$ (5,405)	$ (2,938)	$ (1,967)	$ 19,235	$ 917,779
28	Operating Income	$ 104,677	$ 4,486	$ 713	$ 364	$ 28,351	$ -	$ 19	$ 5,405	$ 2,938	$ 1,967	$ (19,235)	$ 129,685

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule WAR-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule WAR-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule WAR-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule WAR-10
7 - Depreciation Expense	Testimony, WAR And Schedule WAR-11
8 - Property Tax Expense	Testimony, WAR And Schedule WAR-12
9 - Rate Case Expense	Testimony, WAR And Schedule WAR-13
10 - Income Tax	Testimony, WAR And Schedule WAR-14

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

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WAR-7	1	OPERATING INCOME
WAR-8	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
WAR-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 2,338,005	$ 2,319,736
2	Adjusted Operating Income (Loss)	$ (75,247)	$ (59,267)
3	Current Rate of Return (L2 / L1)	-3.22%	-2.55%
4	Required Operating Income (L5 X L1)	$ 229,458	$ 170,037
5	Required Rate of Return on Fair Value Rate Base	9.81%	7.33%
6	Operating Income Deficiency (L4 - L2)	$ 304,705	$ 229,304
7	Gross Revenue Conversion Factor (WAR-1, Page 2)	1.6286	1.6286
8	Required Increase in Gross Revenue Requirement (L7 X L6)	$ 496,253	$ 373,452
9	Adjusted Test Year Revenue	$ 507,981	$ 507,981
10	Proposed Annual Revenue (L8 + L9)	$ 1,004,234	$ 881,433
11	Required Percentage Increase in Revenue (L8 / L9)	97.69%	73.52%
12	Consolidated Revenue Adjustment	$ (222,992)	$ (10,706)
13	Required Increase in Gross Revenue Under Proposed Consolidation	$ 273,068	$ 362,746
14	Required Revenue Under Proposed Consolidation	$ 780,936	$ 870,727
15	Required Percentage Increase in Revenue Under Proposed Consolidation	53.77%	71.41%
16	Rate of Return on Common Equity	12.40%	8.33%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule WAR-2, WAR-7, and WAR-13

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3860			
3	Subtotal (L1 - L2)	0.6140			
4	**Revenue Conversion Factor** (L1 / L3)	**1.6286**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	34.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	31.6309%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	38.5989%			
11	Required Operating Income (Sch. WAR-1, Pg 1, C (B), L4)	$ 170,037			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. WAR-1, Pg 1, C (B), L2)	(59,267)			
13	Required Increase In Operating Income (L11 - L12)		$ 229,304		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 55,706			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	(88,442)			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 144,148		
17	Total Required Increase In Revenue (L13 + L16)		$ 373,452		
	CALCULATION OF INCOME TAX			RUCO Recommended	
18	Revenue (Sch. WAR-1, Pg 1, Col. (B), L12)			$ 881,433	
19	Operating Expense Excluding Income Tax (WAR-7, Col. (E), L27 - L22 - L23)			655,691	
20	Synchronized Interest (Col. (C), L37)			81,423	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 144,320	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 10,056
24	Fed. Taxable Income (L21 - L23)			$ 134,264	
25	Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15%			$ -	
26	Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ -	
27	Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ -	
28	Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ -	
29	Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 45,650	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 45,650
31	Combined Federal and State Income Tax (L23 + L30)				$ 55,706
32	Test Year Combined Income Tax, RUCO as Adjusted (WAR-7, Col. (C), L22 + L23)				$ (88,442)
33	RUCO Adjustment (L31 - L32) (See WAR-6, Col. (D), L23)				$ 144,148
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. WAR-2, Col. (C), L17)			$ 2,319,736	
36	Weighted Avg. Cost of Debt (Sch. WAR-16, Col. (F), L1)			3.51%	
37	Synchronized Interest (L35 X L36)			$ 81,423	

RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
	Plant Classification			
1	Intangible Plant	$ 401	$ -	$ 401
2	Source of Supply Plant	597,457	(62,097)	535,360
3	Pumping Plant	419,745	-	419,745
4	Water Treatment Plant	372,768	-	372,768
5	Transmission & Distribution Plant	3,355,961	-	3,355,961
6	General Plant	196,495	-	196,495
7	Total Gross Plant in Service	$ 4,942,827	$ (62,097)	$ 4,880,730
8	Accumulated Depreciation	(1,104,418)	60,799	(1,043,619)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 3,838,409	$ (1,298)	$ 3,837,112
10	Advances In Aid Of Const.	$ (1,080,835)	$ -	$ (1,080,835)
11	Contribution In Aid of Const.	$ (260,411)	$ -	$ (260,411)
12	Accumulated Amortization of CIAC	69,153	-	69,153
13	NET CIAC (L5 + L6)	$ (191,258)	$ -	$ (191,258)
14	Deferred Income Tax	$ (283,642)	$ -	$ (283,642)
15	Customer Deposits	$ -	$ (7,050)	$ (7,050)
16	Allowance for Working Capital	$ 55,331	$ (9,921)	$ 45,410
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
18	Rounding	$ -	$ -	$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 2,338,005	$ (18,269)	$ 2,319,736

References:
Column (A): Company Schedule B-1
Column (B): Schedule WAR-3
Column (C): Column (A) + Column (B)

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Rimrock System - Surrebuttal
Schedule WAR-3

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJMT NO. 1 PLANT & ACCUM DEP.	(C) ADJMT NO. 2	(D) ADJMT NO. 3 PER BKB 11.16	(E) ADJMT NO. 4	(F) ADJMT NO. 5 CUSTOMER DEPOSITS	(G) ADJMT NO. 6 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
	Plant Classification								
1	Intangible Plant	$ 401	$ -	$ -	$ -	$ -	$ -	$ -	$ 401
2	Source of Supply Plant	597,457	-	-	(62,097)	-	-	-	535,360
3	Pumping Plant	419,745	-	-	-	-	-	-	419,745
4	Water Treatment Plant	372,768	-	-	-	-	-	-	372,768
5	Transmission & Distribution Plant	3,355,961	-	-	-	-	-	-	3,355,961
6	General Plant	196,495	-	-	-	-	-	-	196,495
7	Total Gross Plant in Service	$ 4,942,827	$ -	$ -	$ (62,097)	$ -	$ -	$ -	$ 4,880,730
8	Accumulated Depreciation	(1,104,418)	487	-	60,312	-	-	-	(1,043,619)
9	Net Utility Plant In Service (Sum L1 & L2)	$ 3,838,409	$ 487	$ -	$ (1,785)	$ -	$ -	$ -	$ 3,837,112
10	Advances In Aid Of Const.	$ (1,080,835)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,080,835)
11	Contribution In Aid of Const.	$ (260,411)	$ -	$ -	$ -	$ -	$ -	$ -	$ (260,411)
12	Accumulated Amortization of CIAC	69,153	-	-	-	-	-	-	69,153
13	NET CIAC (L5 + L6)	$ (191,258)	$ -	$ -	$ -	$ -	$ -	$ -	$ (191,258)
14	Deferred Income Tax	$ (283,642)	$ -	$ -	$ -	$ -	$ -	$ -	$ (283,642)
15	Customer Deposits	$ -	$ -	$ -	$ -	$ -	$ (7,050)	$ -	$ (7,050)
16	Allowance for Working Capital	$ 55,331	$ -	$ -	$ -	$ -	$ -	$ (9,921)	$ 45,410
17	Net Regulatory Asset / (Liability)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Rounding	$ -							$ -
19	TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16)	$ 2,338,005	$ 487	$ -	$ (1,785)	$ -	$ (7,050)	$ (9,921)	$ 2,319,736

References:
Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Test-Year Plant, PTY Plant & Accumulated Depreciation (See WAR-4 Total, WAR-4 Direct, WAR-4 PHX OFF and WAR-4 MS Schedules and WAR Tes
Column (C): Adjustment No. 2 - Intentionally Left Blank
Column (D): Adjustment No. 3 - Conforming Adkustment Per Data Response to BKB 11.16 to Remove Plant and Record Retirements
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Customer Deposits
Column (G): Adjustment No. 6 - Working Capital
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Operating Revenues					
1	Residential	$ 471,523	$ -	$ 471,523	$ 373,452	$ 844,975
2	Commercial	17,845	-	17,845	-	17,845
3	Industrial	-	-	-	-	-
4	Private Fire Service	51	-	51	-	51
5	Other Water Revenues	10,101	-	10,101	-	10,101
6	Total Water Revenues	$ 499,521	$ -	$ 499,521	$ 373,452	$ 872,972
7	Miscellaneous	$ 8,461	$ -	$ 8,461	$ -	$ 8,461
8	Total Operating Revenues	$ 507,981	$ -	$ 507,981	$ 373,452	$ 881,433
	Operating Expenses					
	Source of Supply Expenses:					
9	Purchased Water	$ -	$ -	$ -	$ -	$ -
10	Other	1,425	-	1,425	-	1,425
11	Pumping Expenses:	-				
12	Purchased Power	43,401	-	43,401	-	43,401
13	Purchased Gas	-	-	-	-	-
14	Other	24,368	-	24,368	-	24,368
15	Water Treatment Expenses	201,774	-	201,774	-	201,774
16	Transmission & Distribution Expenses	73,189	-	73,189	-	73,189
17	Customer Accounting Expenses	61,306	-	61,306	-	61,306
18	Sales Expense	537	-	537	-	537
19	Administrative & General Expenses	118,572	(23,248)	95,324	-	95,324
20	Total Operations & Maintenance Expense	$ 524,571	$ (23,248)	$ 501,323	$ -	$ 501,323
21	Depreciation & Amortization Expenses	$ 124,861	$ (3,234)	$ 121,627	$ -	$ 121,627
	Taxes					
22	Federal Income Taxes	$ (83,435)	$ 10,958	$ (72,476)	$ 118,126	$ 45,650
23	State Income Taxes	(18,380)	2,414	(15,966)	26,022	10,056
24	Property Taxes	27,191	(2,512)	24,679	-	24,679
25	Other	8,420	(358)	8,062	-	8,062
26	Total Taxes	$ (66,204)	$ 10,502	$ (55,702)	$ 144,148	$ 88,447
27	Total Operating Expenses	$ 583,228	$ (15,980)	$ 567,248	$ 144,148	$ 711,396
28	Operating Income	$ (75,247)	$ 15,980	$ (59,267)	$ 229,304	$ 170,037

References:
Column (A): Company Schedule C-1
Column (B): WAR-8, Columns (B) Thru (I)
Column (C): Column (A) + Column (B)
Column (D): WAR-1
Column (E): Column (C) + Column (D)

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJMT NO. 1 LABOR EXPENSE	(C) ADJMT NO. 2 PAYROLL TAX EXPENSE	(D) ADJMT NO. 3 401(K) EXPENSE	(E) ADJMT NO. 4 REVERSE ADJ. FOR CONSERVATION	(F) ADJMT NO. 5 PURCH. POWER REVENUES	(G) ADJMT NO. 6 INSURANCE EXPENSE	(H) ADJMT NO. 7 DEPRECIATION EXPENSE	(I) ADJMT NO. 8 PROPERTY TAX	(J) ADJMT NO. 9 RATE CASE EXPENSE	(K) ADJMT NO. 10 INCOME TAXES	(L) RUCO AS ADJT'D
	Operating Revenues												
1	Residential	$ 471,523	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 471,523
2	Commercial	17,845	-	-	-	-	-	-	-	-	-	-	17,845
3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-
4	Private Fire Service	51	-	-	-	-	-	-	-	-	-	-	51
5	Other Water Revenues	10,101	-	-	-	-	-	-	-	-	-	-	10,101
6	Total Water Revenues	$ 499,521	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 499,521
7	Miscellaneous	$ 8,461	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,461
8	Total Operating Revenues	$ 507,981	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 507,981
	Operating Expenses												
	Source of Supply Expenses:												
9	Purchased Water	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Other	1,425	-	-	-	-	-	-	-	-	-	-	1,425
11	Pumping Expenses:												
12	Purchased Power	43,401	-	-	-	-	-	-	-	-	-	-	43,401
13	Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-
14	Other	24,368	-	-	-	-	-	-	-	-	-	-	24,368
15	Water Treatment Expenses	201,774	-	-	-	-	-	-	-	-	-	-	201,774
16	Transmission & Distribution Expenses	73,189	-	-	-	-	-	-	-	-	-	-	73,189
17	Customer Accounting Expenses	61,306	-	-	-	-	-	-	-	-	-	-	61,306
18	Sales Expense	537	-	-	-	-	-	-	-	-	-	-	537
19	Administrative & General Expenses	118,572	(2,251)	-	(183)	(19,820)	-	(8)	-	-	(987)	-	95,324
20	Total Operations & Maintenance Expense	$ 524,571	$ (2,251)	$ -	$ (183)	$ (19,820)	$ -	$ (8)	$ -	$ -	$ (987)	$ -	$ 501,323
21	Depreciation & Amortization Expenses	$ 124,861	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,234)	$ -	$ -	$ -	$ 121,627
	Taxes												
22	Federal Income Taxes	$ (83,435)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,958	$ (72,476)
23	State Income Taxes	(18,380)	-	-	-	-	-	-	-	-	-	2,414	(15,966)
24	Property Taxes	27,191	-	-	-	-	-	-	-	(2,512)	-	-	24,679
25	Other	8,420	-	(358)	-	-	-	-	-	-	-	-	8,062
26	Total Taxes	$ (66,204)	$ -	$ (358)	$ -	$ -	$ -	$ -	$ -	$ (2,512)	$ -	$ 13,372	$ (55,702)
27	Total Operating Expenses	$ 583,228	$ (2,251)	$ (358)	$ (183)	$ (19,820)	$ -	$ (8)	$ (3,234)	$ (2,512)	$ (987)	$ 13,372	$ 567,248
28	Operating Income	$ (75,247)	$ 2,251	$ 358	$ 183	$ 19,820	$ -	$ 8	$ 3,234	$ 2,512	$ 987	$ (13,372)	$ (59,267)

ADJUSTMENTS:	REFERENCE:
1 - Labor Expense - Normalize OT Hours in Test Year	Testimony, WAR And Schedule WAR-9 Page, 1 of 3
2 - Payroll Tax Expense Related to Adjustment 1	Testimony, WAR And Schedule WAR-9 Page, 2 of 3
3 - 401(K) Expense Related to Adjustment 1	Testimony, WAR And Schedule WAR-9 Page, 3 of 3
4 - Reverse Adjustment for Conservation	Testimony WAR
5 - Purchased Power Revenues	Testimony WAR
6 - Insurance Expense	Testimony, WAR And Schedule WAR-10
7 - Depreciation Expense	Testimony, WAR And Schedule WAR-11
8 - Property Tax Expense	Testimony, WAR And Schedule WAR-12
9 - Rate Case Expense	Testimony, WAR And Schedule WAR-13
10 - Income Tax	Testimony, WAR And Schedule WAR-14

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Short-Term Debt	$ 7,300,000	4.80%	3.00%	0.14%
2	Long-Term Debt	$ 75,000,000	49.35%	6.83%	3.37%
3	Common Equity	69,671,689	45.85%	8.33%	3.82%
4	Total Capitalization	$ 151,971,689	100.00%		
5	WEIGHTED AVERAGE COST OF CAPITAL				7.33%

References:
Columns (A) Thru (D): Testimony, WAR

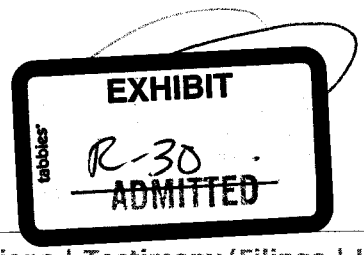
EXHIBIT
R-29
ADMITTED

Arizona Water Company
Docket No. W-01445A-08-0440
Test Year Ended December 31, 2007

Docket No. W-01445A-08-0440

OVERTIME NORMALIZATION ADJUSTMENTS EXHIBIT

	RUCO DIRECT TESTIMONY						RUCO SURREBUTTAL TESTIMONY						DIFFERENCE	
LINE NO.	SYSTEM NAME	(A) ADJMT NO. 1 LABOR EXPENSE	(B) ADJMT NO. 2 PAYROLL TAX EXPENSE	(C) ADJMT NO. 3 401(K) EXPENSE	(D) ADJMT NO. 6 INSURANCE EXPENSE	(E) TOTAL	SYSTEM NAME	(A) ADJMT NO. 1 LABOR EXPENSE	(B) ADJMT NO. 2 PAYROLL TAX EXPENSE	(C) ADJMT NO. 3 401(K) EXPENSE	(D) ADJMT NO. 6 INSURANCE EXPENSE	(E) TOTAL	(F) ($) DIFFERENCE	(F) (%) DIFFERENCE
1	Bisbee	$ (15,077)	$ (1,127)	$ (1,266)	$ (45)	$ (17,514)	Bisbee	$ (7,573)	$ (566)	$ (636)	$ (23)	$ (8,797)	$ 8,716	-49.77%
2	Miami	(15,077)	(1,127)	(1,266)	(40)	(17,509)	Miami	(7,573)	(566)	(636)	(20)	(8,795)	8,714	-49.77%
3	Oracle	(6,903)	(516)	(579)	(20)	(8,018)	Oracle	(3,467)	(259)	(291)	(10)	(4,028)	3,990	-49.77%
4	San Manuel	(5,086)	(380)	(427)	(20)	(5,913)	San Manuel	(2,555)	(191)	(214)	(10)	(2,970)	2,943	-49.77%
5	Sierra Vista	(7,811)	(584)	(656)	(38)	(9,088)	Sierra Vista	(3,923)	(293)	(329)	(19)	(4,565)	4,523	-49.77%
6	Superstition	(75,504)	(5,642)	(6,338)	(273)	(87,757)	Superstition	(37,927)	(2,834)	(3,184)	(137)	(44,082)	43,675	-49.77%
7	Winkelman	(666)	(50)	(56)	(2)	(774)	Winkelman	(335)	(25)	(28)	4	(384)	390	-50.44%
8	Ajo	(2,452)	(286)	(207)	(9)	(2,954)	Ajo	(1,232)	(143)	(104)	(4)	(1,484)	1,470	-49.77%
9	Casa Grande	(80,379)	(9,363)	(6,793)	(595)	(97,129)	Casa Grande	(40,375)	(4,703)	(3,412)	(299)	(48,789)	48,340	-49.77%
10	Coolidge	(15,955)	(1,858)	(1,348)	(62)	(19,223)	Coolidge	(8,014)	(934)	(677)	(31)	(9,656)	9,567	-49.77%
11	Stanfield	(817)	(95)	(69)	(3)	(984)	Stanfield	(411)	(48)	(35)	(1)	(495)	490	-49.77%
12	White Tank	(7,175)	(836)	(606)	(22)	(8,639)	White Tank	(3,604)	(420)	(305)	(11)	(4,340)	4,300	-49.77%
13	Lakeside	(18,770)	(2,984)	(1,524)	(65)	(23,343)	Lakeside	(9,429)	(1,499)	(766)	(33)	(11,726)	11,618	-49.77%
14	Overgaard	(12,079)	(1,920)	(981)	(55)	(15,036)	Overgaard	(6,068)	(965)	(493)	(28)	(7,553)	7,483	-49.77%
15	Pinewood	(8,931)	(1,420)	(725)	(38)	(11,114)	Pinewood	(4,486)	(713)	(364)	(19)	(5,583)	5,531	-49.77%
16	Rimrock	(4,481)	(712)	(364)	(16)	(5,573)	Rimrock	(2,251)	(358)	(183)	(8)	(2,799)	2,774	-49.77%
17	Sedona	(25,582)	(4,067)	(2,077)	(84)	(31,810)	Sedona	(12,850)	(2,043)	(1,043)	(42)	(15,979)	15,831	-49.77%
18	Totals	$ (302,744)	$ (32,966)	$ (25,281)	$ (1,387)	$(362,378)	Totals	$ (152,073)	$ (16,559)	$ (12,699)	$ (692)	$(182,023)	$ 180,355	-49.77%
19	Total Eastern Group	$ (126,123)	$ (9,424)	$ (10,587)	$ (439)	$(146,573)	Total Eastern Group	$ (63,354)	$ (4,734)	$ (5,318)	$ (215)	$ (73,621)	$ 72,952	-49.77%
20	Total Western Group	(106,778)	(12,438)	(9,024)	(691)	$(128,930)	Total Western Group	(53,636)	(6,248)	(4,533)	(347)	$ (64,763)	$ 64,167	-49.77%
21	Total Northern Group	(69,843)	(11,104)	(5,671)	(257)	$ (86,875)	Total Northern Group	(35,083)	(5,578)	(2,849)	(129)	$ (43,639)	$ 43,237	-49.77%
22	Total Company	$ (302,744)	$ (32,966)	$ (25,281)	$ (1,387)	$(362,378)	Total Company	$ (152,073)	$ (16,559)	$ (12,699)	$ (692)	$(182,023)	$ 180,355	-49.77%



National Association of State Utility Consumer Advocates
R E S O L U T I O N

Discouraging State Regulatory Commissions from Adopting Automatic Adjustment Charges for Water Company Infrastructure Costs

WHEREAS, certain regulated water companies have recently proposed mechanisms for automatically increasing water rates, prior to regulatory review, based upon isolated items of expense related to infrastructure projects; and
WHEREAS, the National Association of State Utility Consumer Advocates (NASUCA) believes that public interest is still best served by rate of return regulation of investor-owned water companies and that such automatic adjustment mechanisms contradict several sound rate of return ratemaking principles, including the matching principle, because increases to items of rate base are recognized far outside of the test year from which all other rate base, as well as revenues, expenses, and cost of capital items that are used when calculating rates, allowing 'piecemeal ratemaking' and preventing the recognition of any simultaneous offsetting reductions in other items; and

WHEREAS, automatic adjustment mechanisms also circumvent regulatory review of increases to rate base for prudence and reasonableness; and

WHEREAS, automatic adjustment mechanisms further create bad public policy by eliminating the built-in regulatory incentive to control costs between rate cases and, generates incentives to increase spending in order to avoid reduction of the surcharge which occurs if the water company's authorized return is reached; and

WHEREAS, when an automatic adjustment clause is adopted, rate stability is reduced and proper price signals are distorted by frequent rate increases, and no convincing evidence has been shown to support the claim that the frequency of rate case proceedings is reduced by such clauses; and

WHEREAS, special incentives are not needed in order ensure adequate water quality, pressure, and a proper reduction of service interruptions; and

WHEREAS, automatic adjustment mechanisms can inappropriately reward water companies that have imprudently fallen behind in infrastructure improvements; and

WHEREAS, it is inappropriate to tilt the regulatory balance against consumers and shift business risk away from water companies simply for the purpose of creating an incentive for these companies to fulfill their basic obligation to provide safe and adequate service;

THEREFORE, BE IT RESOLVED, that NASUCA strongly recommends state legislatures and state public utility commissions avoid the implementation of automatic adjustments charges for water company infrastructure costs; and

BE IT FURTHER RESOLVED, that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution. The Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Approved by NASUCA:

June, 1999, Baltimore, Maryland

Submitted By:

NASUCA Ad Hoc Water Committee

Christine Maloni Hoover, PA, Chair
Wes Blakley, IN
Robert Brabston, NJ
John Coffman, MO
Brian Gallagher, DE
Donald Rogers, MD
Dale Stransky, NV
James Warden, Jr., NY

National Association of State Utility Consumer Advocates
8380 Colesville Road, Suite 101, Silver Spring, MD 20910
Phone: (301) 589-6313 Fax: 589-6380
e-mail: nasuca@nasuca.org

EXHIBIT C

COMPARISION OF MONTHLY INCREASES TO THE AVERAGE 5/8" x 3/4" METERED CUSTOMERS

LINE NO.	SYSTEMS	DESCRIPTION 5/8" x 3/4" Metered Customers	Avg. Gallons	A COMPANY PROPOSED CONSOLIDATION		B RUCO MODIFIED OPTION E WITH ADJUSTED BASE RATES TO MINIMIZE RATES		C STAFF PROPOSED CONSOLIDATED RATE IMPACT	
1	Superstition System	18,257	7,358	$ 5.52	16.36%	$ 0.02	0.05%	$ 1.99	5.89%
2	Bisbee System	3,085	5,215	$ 4.90	16.41%	$ 4.25	14.23%	$ 1.81	6.07%
3	Sierra Vista System	2,664	8,924	$ 0.50	1.67%	**$ (2.37)**	**-7.94%**	$ 0.57	1.92%
4	San Manuel System	1,477	8,745	$ 7.47	17.08%	$ 4.34	9.91%	$ 3.17	7.25%
5	Oracle System	1,389	5,605	$ 2.16	4.56%	**$ (3.64)**	**-7.70%**	**$ (3.68)**	**-7.80%**
6	Winkelman System	144	9,459	$ 10.04	42.38%	$ 5.00	21.10%	$ 7.17	30.27%
7	Miami System	2,820	5,995	$ 0.91	2.67%	$ 5.00	14.59%	**$ (2.85)**	**-8.32%**
8	Casa Grande System	20,642	8,843	$ 6.13	22.87%	$ 3.06	11.55%	$ 1.62	6.12%
9	Stanfield System	179	9,162	**$ (0.19)**	**-0.45%**	$ 5.00	11.74%	**$ (7.72)**	**-18.12%**
10	White Tank System	1,573	15,648	$ 1.75	2.87%	$ 1.38	2.27%	**$ (4.12)**	**-6.78%**
11	Ajo System	604	5,185	$ 8.24	17.70%	$ 1.87	4.02%	$ 5.63	12.08%
12	Coolidge System	4,229	8,134	$ 5.95	23.24%	**$ (0.42)**	**-1.65%**	$ 1.15	4.49%
13	Lakeside System	4,679	4,312	**$ (0.14)**	**-0.40%**	**$ (5.21)**	**-14.33%**	**$ (7.00)**	**-19.24%**
14	Overgaard System	4,110	2,765	**$ (3.60)**	**-11.70%**	**$ (7.18)**	**-23.38%**	**$ (8.96)**	**-29.18%**
15	Sedona System	5,154	10,264	$ 11.11	30.51%	**$ (0.30)**	**-0.83%**	$ 8.07	22.14%
16	Pinewood System	2,862	2,407	$ 1.25	4.33%	**$ (3.24)**	**-11.27%**	**$ (7.75)**	**-26.95%**
17	Rimrock System	1,230	6,165	**$ (1.32)**	**-2.85%**	**$ 5.00**	**10.78%**	**$ (14.64)**	**-31.55%**

Reference:

Column (A): Data Is Based On Information From The Company's Exhibit A-56, Submitted August 10,2009.

Column (B): Data Is From RUCO's Surrebuttal Rate Design. RUCO's Rate Design Will Generate RUCO's Recommended Required Revenue.

Column (C): Data Is Based On Information From Staff's Surrebuttal Rate Design, Which Was Applied To RUCO's Typical Bill Analysis. Staff's Rate Design Will Generate The Required Revenue Recommended By Staff.

Note:

RUCO's Typical Bill Analysis Included The Appropirate ACRM Surcharges In The Present Total Monthly Charges, Which Is Reflected In The Calculation Of The Proposed Monthly Increase.

EXHIBIT
R-31

ARIZONA WATER COMPANY

DOCKET NO. W-01445A-08-0440

DIRECT TESTIMONY
ON COST OF CAPITAL

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 12, 2009

EXHIBIT
R-32
ADMITTED

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SCHEDULES WAR-1 THROUGH WAR-9

INTRODUCTION

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

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. I have been involved with utilities regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to my direct testimony on operating income further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Arizona Water Company's ("AWC" or the "Company") application for a permanent rate increase ("Application") for the Company's statewide Water operations. AWC filed the Application with the Arizona Corporation Commission ("ACC" or "Commission") on August 22, 2008. The Company has chosen the operating period ended December 31, 2007 for the test year ("Test Year") in this proceeding.

Q. Please explain your role in RUCO's analysis of AWC's Application.

A. I reviewed AWC's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity and my recommended cost of long-term debt (AWC has no preferred stock). The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

...

Q. Were you also responsible for conducting an analysis on the Company's proposed revenue level, rate base and rate design?

A. I have filed, under separate cover, direct testimony on the operating income issues associated with AWC's application. RUCO witness Timothy J. Coley will provide direct testimony on the rate base issues in the case and RUCO witness Rodney L. Moore will file direct testimony on RUCO's recommended rate design on Friday, June 26, 2009.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into seven sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past,

and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this third section I will also provide a brief overview of the current economic climate within which AWC is operating. Fourth, I will discuss my recommended cost of long-term debt. Fifth, I will compare my recommended capital structure with the Company-proposed capital structure. Sixth, I will explain my weighted cost of capital recommendation and seventh, I will comment on AWC's cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of AWC, I am making the following recommendations:

Cost of Equity Capital – I am recommending an 8.33 percent cost of equity capital. This 8.33 percent figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies. My 8.33 percent cost of equity capital is 407 basis points lower than the 12.40 percent cost of equity capital being proposed by the Company.

Cost of Long-Term Debt – I am recommending that the Commission adopt the Company-proposed 7.31 percent cost of long-term debt. This is based on my review of the costs associated with AWC's various bond issuances.

Capital Structure – I am recommending that the Commission adopt the Company-proposed capital structure comprised of 50.76 percent long-term debt and 49.24 percent common equity.

Weighted Average Cost of Capital – Based on the results of my recommended capital structure, cost of common equity, and long-term debt analyses, I am recommending a 7.81 percent weighted average cost of capital for AWC. This figure represents the weighted cost of my recommended costs of long-term debt and common equity. My recommended weighted average cost of capital is 200 basis points lower than the 9.81 percent weighted average cost of capital being proposed by the Company.

Q. Why do you believe that your recommended 7.81 percent weighted average cost of capital is an appropriate rate of return for AWC to earn on its invested capital?

A. The 7.81 percent weighted average cost of capital figure that I am recommending meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public

Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as AWC, is provided with the opportunity to earn an appropriate rate of return if the Company's management

exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your final recommended cost of equity capital for AWC?

A. I am recommending a cost of equity of 8.33 percent. My recommended 8.33 percent cost of equity figure represents the 8.33 percent mean average of the results of my DCF and CAPM analyses, which utilized both a sample of publicly traded water providers and a sample of publicly traded natural gas local distribution companies ("LDC"). This calculation is exhibited on page 3 of my Schedule WAR-1.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate AWC's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost

of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = \frac{D_1}{P_0} + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that I used to determine AWC's cost of equity capital.

Q. In determining the rate of future dividend growth for AWC, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as $g = b \times r$.

...

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[1]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I

[1] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[2] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[3] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rate for earnings and dividends, displayed in the last column, is 16.20 percent. If this rate was to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

...

[2] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[3] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an

extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

...

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[4] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where:	g	=	DCF expected growth rate,
	b	=	the earnings retention ratio,
	r	=	the return on common equity,
	s	=	the fraction of new common stock sold that accrues to a current shareholder, and
	v	=	funds raised from the sale of stock as a fraction of existing equity.
and	v	=	$1 - [(BV) \div (MP)]$
where:	BV	=	book value per share of common stock, and
	MP	=	the market price per share of common stock.

...

[4] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In a prior Southwest Gas Corporation rate case[5], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill

[5] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on two separate proxy groups. A water company proxy group comprised of three publicly traded water companies and a natural gas proxy group consisting of ten natural gas local distribution companies ("LDC") that have similar operating characteristics to water providers.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of AWC?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with AWC itself. Consequently it was necessary to create a proxy by analyzing publicly traded water companies and LDC's with similar risk characteristics.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is

commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the companies that make up your water company proxy for AWC?

A. The three water companies used in the proxy are publicly traded on the New York Stock Exchange ("NYSE"). All three water companies are followed by The Value Line Investment Survey ("Value Line") and are the same companies that comprise Value Line's large capitalization Water Utility Industry segment of the U.S. economy (Attachment A contains Value Line's April 24, 2009 update of the water utility industry and evaluations of the water companies used in my proxy).

Q. Are these the same water utilities that you have used in prior rate case proceedings?

A. Yes. However, in prior proceedings I have also included a fourth water provider known as Southwest Water Company which is traded over the counter through the National Association of Securities Dealers Automated Quotation System ("NASDAQ").

Q. Why did you exclude Southwest Water Company from your sample in this proceeding?

A. Value Line has suspended its long-term projections on Southwest Water Company as a result of accounting errors that were recently discovered by Southwest Water Company's management. The lack of projected data made Southwest Water Company unsuitable for my sample group of water providers.

Q. Please describe the companies that comprise your water company proxy group.

A. My water company proxy group includes American States Water Co. (stock ticker symbol "AWR"), California Water Service Group ("CWT") and Aqua America, Inc. ("WTR"). Each of these water companies face the same types of risk that AWC faces. For the sake of brevity, I will refer to each of these companies by their appropriate stock ticker symbols henceforth.

Q. Briefly describe the areas served by the companies in your water company sample proxy.

A. In addition to providing water service to residents of Fountain Hills, Arizona through its wholly owned subsidiary Chaparral City Water Company, AWR also serves communities located in Los Angeles, Orange and San Bernardino counties in California. CWT provides service to

customers in seventy-five communities in California, New Mexico and Washington. CWT's principal service areas are located in the San Francisco Bay area, the Sacramento, Salinas and San Joaquin Valleys and parts of Los Angeles. WTR is a holding company for a large number of water and wastewater utilities operating in nine different states including Pennsylvania, Ohio, New Jersey, Illinois, Maine, North Carolina, Texas, Florida and Kentucky.

Q. Are these the same water companies that AWC used in its application?

A. AWC's cost of equity witness, Dr. Thomas Zepp, used the same water companies included in my proxy. Dr. Zepp also used three other water companies in his cost of capital analysis[6] which are included in Value Line's Small and Mid Cap Edition.

Q. Why did you exclude the water companies that are followed in Value Line's Small and Mid Cap Edition?

A. Value Line does not provide the same type of forward-looking information (i.e. long-term estimates on return on common equity and share growth) on small and mid-cap companies that it provides on the three water companies that I used in my proxy. Consequently, as in the case of Southwest Water Company, these water providers are not as suitable as the ones that I have used in my analysis.

[6] Connecticut Water Service, Inc., Middlesex Water Company and SJW Corp.

Q. What criteria did you use in selecting the natural gas LDC's included in your proxy for AWC?

A. As are the water companies that I just described, each of the natural gas LDC's used in the proxy are publicly traded on a major stock exchange (all ten trade on the NYSE) and are followed by Value Line. Each of the ten LDC's in my sample are tracked in Value Line's natural gas Utility industry segment. All of the companies in the proxy are engaged in the provision of regulated natural gas distribution services. Attachment B of my testimony contains Value Line's most recent evaluation of the natural gas proxy group that I used for my cost of common equity analysis.

Q. What companies are included your natural gas proxy?

A. The ten natural gas LDC's included in my proxy (and their NYSE ticker symbols) are AGL Resources, Inc. ("AGL"), Atmos Energy Corp. ("ATO"), Laclede Group, Inc. ("LG"), New Jersey Resources Corporation ("NJR"), Nicor, Inc. ("GAS"), Northwest Natural Gas Co. ("NWN"), Piedmont Natural Gas Company ("PNY"), South Jersey Industries, Inc. ("SJI") Southwest Gas Corporation ("SWX"), which is the dominant natural gas provider in Arizona, and WGL Holdings, Inc. ("WGL"). These are the same ten LDC's that I analyzed in the most recent UNS Gas, Inc. proceeding.[7]

[7] Docket No. G-04204A-06-0463

Q. Briefly describe the regions of the U.S. served by the ten natural gas LDC's that make up your sample proxy.

A. The ten LDC's listed above provide natural gas service to customers in the Middle Atlantic region (i.e. NJI which serves portions of northern New Jersey, SJI which serves southern New Jersey and WGL which serves the Washington D.C. metro area), the Southeast and South Central portions of the U.S. (i.e. AGL which serves Virginia, southern Tennessee and the Atlanta, Georgia area and PNY which serves customers in North Carolina, South Carolina and Tennessee), the South, deep South and Midwest (i.e. ATO which serves customers in Kentucky, Mississippi, Louisiana, Texas, Colorado and Kansas, GAS which provides service to northern and western Illinois, and LG which serves the St. Louis area), and the Pacific Northwest (i.e. NWN which serves Washington state and Oregon). Portions of Arizona, Nevada and California are served by SWX.

Q. Did the Company's witness also perform a similar analysis using natural gas LDC's?

A. No, he did not.

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and

the compounded share growth for each of the utilities included in the sample for the historical observation period 2004 to 2008 for both the water and LDC industries. Schedule WAR-5 also includes Value Line's projected 2009, 20010 and 2012-14 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for both the water utilities and the LDC's.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use AWR as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on pages 10 and 11) to multiply AWR's earned return on common equity by its earnings retention ratio for each year in the 2003 to 2007 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, AWR's average internal growth rate of 2.62 percent over the 2004 to 2008 time frame reflects an up and down pattern of growth that ranged from a low of 1.01 percent in 2002 to a high of 3.79 percent during 2007. Value Line is predicting that growth will

increase steadily from 3.05 percent in 2008, to 6.35 percent by the end of the 2012-14 time frame. After weighing Value Line's projections for internal growth, lower outlook for earnings per share, no change in dividends and a higher estimate for book value, I believe that a 6.00 percent rate of growth is reasonable for AWR (Schedule WAR-4, Page 1 of 2).

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that the pattern of shares outstanding for AWR increased from 16.75 million to 17.30 million from 2004 to 2008. Value Line is predicting that this level will increase from 18.25 million in 2008 to 20.25 million by the end of 2014. Based on this data, I believe that a 4.75 percent growth in shares is not unreasonable for AWR (Page 2 of Schedule WAR-4). My final dividend growth rate estimate for AWR is 7.81 percent (6.00 percent internal + 1.81 percent external) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average DCF dividend growth rate estimate for your sample of water utilities?

A. My average DCF dividend growth rate estimate for my water company sample is 6.25 percent as displayed on page 1 of Schedule WAR-4.

Q. Did you use the same approach to determine an average dividend growth rate for the proxy comprised of natural gas LDC's?

A. Yes.

Q. What is your average DCF dividend growth rate estimate for the sample natural gas utilities?

A. My average DCF dividend growth rate estimate is 6.44 percent, which is also displayed on page 1 of Schedule WAR-4.

Q. How does your average dividend growth rate estimates on water companies compare to the growth rate data published by Value Line and other analysts?

A. Schedule WAR-6 compares my sustainable growth estimates with the five-year projections of analysts at both Zacks Investment Research, Inc. ("Zacks") (Attachment C) and Value Line. In the case of the water companies, my 6.25 percent estimate falls between Zacks' average long-term EPS projection of 8.33 percent and Value Line's growth projection of 5.36 percent (which is an average of EPS, DPS and BVPS). My 6.25 percent estimate is 38 basis points higher than the 5.87 percent average of Value Line's historical and projected data (and the consensus opinions published by Zacks) and is also 69 basis points higher than Value Line's 5.56 percent 5-year compound historical average of EPS, DPS and BVPS. The estimates of analysts at Value Line indicate that investors are

expecting somewhat lower increased performance from water utilities in the future. On balance, I would say my 6.25 percent estimate is a good representation of the growth projections that are available to the investing public.

Q. How do your average dividend growth rate estimates on natural gas LDC's compare to the growth rate data published by Value Line and other analysts?

A. In regard to the natural gas LDC's, my 6.44 percent estimate also falls between the average 6.59 percent long-term consensus projections published by Zacks, and the 4.33 percent Value Line projected estimate (which is an average of EPS, DPS and BVPS). As can also be seen on Schedule WAR-6, the 6.44 percent estimate that I have calculated is 76 basis points higher than the 5.68 percent average of the 5-year historic EPS, DPS and BVPS means of Value Line and 108 basis points higher than the 5.36 percent five-year compound historical average of Value Line data (on EPS, DPS and BVPS). In fact, my 6.44 percent estimate is 122 basis points higher than the combined 5.22 percent Value Line and Zacks averages displayed in Schedule WAR-6. The estimates of both Value Line's and Zacks' analysts indicate that investors are also expecting somewhat lower performance from natural gas distribution companies in the future. In the case of the LDC's I would say that my 6.44 percent estimate, which is lower than Zack's projections but higher than Value

Line's forecasts, is a fair representation of the growth projections presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. For both the water companies and the natural gas LDC's I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's April 24, 2009 Ratings and Reports water services industry update and Value Line's March 13, 2009 Ratings and Reports natural gas utility update. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period April 6, 2009 to May 29, 2009.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the water and natural gas utilities included in your sample?

A. As shown on page 2 of Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 9.32 percent for the water utilities and 11.42 percent for the natural gas LDC's.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind CAPM and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[8], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[9] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification.

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[8] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[9] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

where:

k	=	the expected return of a given security,
r_f	=	risk-free rate of return,
ß	=	beta coefficient, a statistical measurement of a security's systematic risk,
r_m	=	average market return (e.g. S&P 500), and
$r_m - r_f$	=	market risk premium.

Q. What types of financial instruments are generally used as a proxy for the risk-free rate of return in the CAPM model?

A. Generally speaking, the yields of U.S. Treasury instruments are used by analysts as a proxy for the risk-free rate of return component.

...

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[10] a real rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the real rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my

[10] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the real rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

testimony, this compensation translates into higher rates of returns to the investor.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used an eight-week average of the yield on a 5-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated April 10, 2009 through May 29, 2009 (Attachment D). This resulted in a risk-free (r_f) rate of return of 1.87 percent.

Q. Why did you use the yield on a 5-year year U.S. Treasury instrument as opposed to a short-term T-Bill?

A. While a shorter term instrument, such as a 91-day T-Bill, presents the lowest possible total risk to an investor, a good argument can be made that the yield on an instrument that matches the investment period of the asset being analyzed in the CAPM model should be used as the risk-free rate of return. Since utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury Instrument closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect.

...

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical total returns on the S&P 500 index from 1926 to 2007 as the proxy for the market rate of return (r_m). For the risk-free portion of the risk premium component (r_f), I used the geometric mean of the total returns of long-term government bonds for the same eighty-one year period. The market risk premium (r_m - r_f) that results by using these inputs is 5.10 percent (10.40% - 5.30% = 5.10%). The market risk premium that results by using the arithmetic mean calculation is 6.80 percent (12.30% - 5.50% = 6.80%).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in both my proxies, were calculated by Value Line and were current as of April 24, 2009 for the water companies and March 13, 2008 for the natural gas LDC's. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the service providers included in my water company sample ranged from 0.75 to 0.85 with an average beta of 0.82. The beta

coefficients for the LDC's included in my natural gas sample ranged from 0.60 to 0.75 with an average beta of 0.67.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 6.04 percent for the water companies and 5.26 percent for the natural gas LDC's. My calculation using an arithmetic mean results in an average expected return of 7.43 percent for the water companies and 6.39 percent for the natural gas LDC's.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF (Water Sample)	9.32%
DCF (Natural Gas Sample)	11.42%
CAPM (Water Sample)	6.04% – 7.43%
CAPM (Natural Gas)	5.26% – 6.39%

Based on these results, my best estimate of an appropriate range for a cost of common equity for AWC is 5.26 percent to 11.42 percent. My final recommended cost of common equity figure is 8.33 percent.

Q How did you arrive at your final recommended 8.33 percent cost of common equity?

A. My recommended 8.33 percent cost of common equity is the mean average of my DCF and CAPM results. The calculation of my 8.33 percent cost of common equity can be seen on Schedule WAR-1, Page 2 of 2.

Q. Did you make any direct adjustment to your recommended cost of common equity that takes into consideration the higher level of equity contained in AWC's capital structure?

A. No. As can be seen in Schedule WAR- 9, the Company-proposed capital structure is in line with the capital structures of the water utilities included in my sample and is roughly in line with the capital structures of the LDC's included in my sample.

...

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 12.40 percent cost of equity capital proposed by the Company is 407 basis points higher than the 8.33 percent OCRB cost of equity capital that I am recommending.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[11] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

[11] This is the interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance,"

pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding a recession.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates – moves

which indicated that the worst may be over and that the recession might have bottomed out during the last quarter of 2001 – a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in forty-five years.

Even though some signs of economic strength, mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.[12]"

...

[12] Wolk, Martin, "Fed holds interest rates steady," MSNBC, January 28, 2004.

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief.

As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What was the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the federal funds rate of 5.25 percent established on June 29, 2006.

Q. How did analysts view the Fed's actions between January 2001 and August 2006?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[13] In other words, the Fed was trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[14]

...

[13] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[14] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings – like the one that the Fed managed to pull off during the 1994-95 time frame, in which a recession or a bear market were avoided – rarely happen[15]. Since it began increasing the federal funds rate in June 2004, the Fed had assured investors that it would increase rates at a "measured" pace. Many analysts and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[16]. According to Mr. Browning, at the time that his article was published, the hope was that Chairman Bernanke would succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

[15] Browning, E.S, "Not Too Fast, Not Too Slow...," The Wall Street Journal Online Edition, August 21, 2006.

[16] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

Q. Was the Fed's attempt to engineer a soft landing successful during the period that followed the August 8, 2006 FOMC meeting?

A. It would appear so. Articles published in the mainstream financial press were generally upbeat on the economy during that period. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low; wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[17]

Q. What has been the state of the economy over the past two years?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate

[17] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

unchanged at 5.25 percent.[18] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crisis rooted in a deterioration of the market for subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through open market operations) into the credit markets.[19] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal, [20] the Fed had used all of its tools to restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate – possibly before the next FOMC meeting scheduled on September 18, 2007.

[18] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

[19] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[20] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points (25 basis points more than what was anticipated). This brought the federal funds rate down to a level of 4.75 percent. The Fed's action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175 basis points to a level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

Q. What actions has the Fed taken in regard to interest rates over the past year?

A. The Fed made two more rate cuts which included a 75 basis point reduction in the federal funds rate on March 18, 2008 and an additional 25 basis point reduction on April 30, 2008. The Fed's decision to cut rates was based on its belief that the slowing economy was a greater concern than the current rate of inflation (which the majority of FOMC members

1 believed would moderate during the economic slowdown).[21] As a result of
2 the Fed's actions, the federal funds rate was reduced to a level of 2.00
3 percent. From April 30, 2008 through September 16, 2008, the Fed took
4 no further action on its key interest rate. However, the days before and
5 after the Fed's September 16, 2008 meeting saw longstanding Wall Street
6 firms such as Lehman Brothers, Merrill Lynch and AIG failing as a result of
7 their subprime holdings. By the end of the week, the Bush administration
8 had announced plans to deal with the deteriorating financial condition
9 which had now become a worldwide crisis. The administrations actions
10 included former Treasury Secretary Henry Paulson's request to Congress
11 for $700 billion to buy distressed assets as part of a plan to halt what has
12 been described as the worst financial crisis since the 1930's[22]. Amidst this
13 turmoil, the Fed made the decision to cut the federal funds rate by another
14 50 basis points in a coordinated move with foreign central banks on
15 October 8, 2008. This was followed by another 50 basis point cut during
16 the regular FOMC meeting on October 29, 2008. At the time of this
17 writing, the federal funds target rate now stands at 0.25 percent, the result
18 of a 75 basis point cut announced on December 16, 2008. After FOMC
19 meetings in January, March and April of 2009, the Fed elected not to
20 make any changes in the federal funds rate, stating in January that the

[21] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

[22] Soloman, Deborah, Michael R. Crittenden and Damian Paletta, "U.S. Bailout Plan Calms Markets, But Struggle Looms Over Details" The Wall Street Journal, September 20, 2008

rate would remain low "for some time."[23] Presently, the Fed's discount rate is at 0.50 percent, a level not seen since 1940s.[24] Based on data released during the early part of December 2008, the U.S. is now officially in a recession which began in December of 2007.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected benchmark rates?

A. U.S. Treasury instruments are for the most part still at historically low levels. The Fed's actions have also had the overall effect of reducing the cost of many types of business and consumer loans. As can be seen in Schedule WAR-8, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has fallen to 0.50 percent from 2.25 percent in 2008.

Q. What has been the trend in other leading interest rates over the last year?

A. As of May 20, 2009, the leading interest rates have all dropped from the levels that existed a year ago (Attachment C, Value Line Selection & Opinion page 3517). The prime rate has fallen from 5.00 percent a year ago to 3.25 percent. The benchmark federal funds rate, just discussed, has decreased from 2.00 percent, in May 2008, to a level of 0.25 percent

[23] Hilsenrath, Jon and Liz Rappaport, "Fed Weighs Idea of Buying Treasurys as Focus Shifts" The Wall Street Journal, January 29, 2009

[24] Hilsenrath, Jon, "Fed Cuts Rates Near Zero to Battle Slump" The Wall Street Journal, December 17, 2008

(as a result of the December 16, 2008 rate cut discussed above). The yields on all of the non-inflation protected maturities of U.S. Treasury instruments exhibited in my Attachment C have also decreased over the past year. A previous trend, described by former Chairman Greenspan as a "conundrum"[25], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, is completely reversed and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists (Attachment C). The 5-year Treasury yield, used in my CAPM analysis, has fallen from 3.04 percent, in May 2008, to 2.03 percent as of May 20, 2009. The 30-Year Treasury constant maturity rate also decreased from 4.54 percent over the past year to 4.14 percent. These current yields are considerably lower than corresponding yields that existed during the early nineties and at the beginning of the current decade (as can be seen on Schedule WAR-8).

Q. What is the current outlook for the economy?

A. Value Line's analysts have become more optimistic in their outlook on the economy as of late and had this to say in their Quarterly Economic Review that appeared in the May 29, 2009 edition of Value Line's Selection and Opinion publication:

[25] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005

> **We probably have seen the low point in the business cycle,** with the six month period from early last fall through late this winter likely having marked that trough. The business outlook, which deteriorated steadily during this time—with housing, auto demand, retail sales, manufacturing, and on manufacturing all slumping in tandem— has grown less troubling in recent weeks. The lessening in the recession's clout suggests that the U.S. gross domestic product, which fell 6.3% in the fourth quarter of 2008 and by 6.1% in the opening period of this year, will decline by less than half that amount in the quarter that ends on June 30th. It should be noted that the surveys being issued largely detail a reduction in the economic downturn's severity, rather than any appreciable pickup in strength. In our view, we are still months away from a sustained business upturn. The best that seems ahead in the next 12 to 18 months is an uneven and understated recovery, with quarterly growth only gradually rising above 2%. We think it will be late 2010 or early 2011 before the economy really gets rolling.

Q. What is Value Line's outlook for interest rates?

A. In the Selection and Opinion publication noted above, Value Line's analysts had this to say:

> **Interest Rates:** Late last year, with the threat of a deepening recession, or worse, increasing by the day, the Federal Reserve voted to lower the Federal Funds rate (the rate charged on overnight loans between banks) to near zero. That is where they remain now and are likely to stay for a year or more. Other short-term interest rates — notably on three-and six-month Treasury bills — remain negligible, as do yields on money market funds and bank certificates of deposit of short duration. Longer-term fixed-income instruments (i.e., 10-year Treasury notes and 30-year Treasury bonds), where yields are more closely tied to long-range inflationary expectations, are also low by recent standards, at 3.2% and 4.2%, respectively. Here, though, yields are trending higher, as some market forecasters opine that inflation will pose a problem later in the pending business recovery. Time will tell if such worries are justified. Long-term interest rates are not yet serious competition for stocks, but they could become so with even a moderate further increase.

Q. What is Value Line's opinion on the current rate of inflation?

A. Also in the Selection and Opinion publication noted above, Value Line's analysts had this to say:

> **Inflation:** The major story here has been the ratcheting down of inflation since late last year, when declining global economic activity and plunging oil prices helped bring about selective deflation, or falling prices. Producer (wholesale) and consumer prices fell further during the opening quarter of 2009, albeit less sharply than in the preceding three months, as demand for labor, raw materials, and energy all contracted. The threat of deflation now seems to be lessening, as the decline in economic activity slows. Our sense is that aggregate price changes will be limited in the second quarter of this year and that inflation will start to selectively edge higher by the fourth quarter. Somewhat higher producer and consumer prices are likely in 2010. We think it will be 2011 or 2012, before there is much chance of an inflation problem.

Q. How are water utilities faring in the current economic environment?

A. Although there are some concerns regarding long-term infrastructure requirements, water utilities appear to be doing well according to Value Line analyst Andre J. Costanza. In the October 24, 2008 quarterly update on the water utility industry Mr. Costanza stated the following:

> The Water Utility Industry has held up relatively well over the past few months. Although the broad market has been sent into a tailspin by growing economic uncertainties and a tightening credit market, water utility stocks have given little, if any, ground, and have thus jumped into the middle of the pack of The Value Line Investment Survey for Timeliness. Companies here are enjoying an increasingly favorable regulatory environment, but the primary reason for the share-price strength boils down to their perceived safety. Indeed, because of the steady stream of income these stocks generate and the necessity for water itself, the group provides shelter for investors looking to get out of the treacherous economic waters that have been pulling many under without having to take too conservative a stance. With no end to the volatility in sight, these stocks are likely to continue outpacing the broad market averages over the coming six to 12 months.

Mr. Costanza reiterated his sentiments on the water utility industry in the Value Line update published on January 23, 2009:

> Not much has changed in the Water Utility Industry since our October report. Stocks here have held their ground for the most part, whereas the broader market continued to struggle with ongoing economic uncertainty. Although an improving regulatory environment has played a hand, the industry is really benefiting from the its perceived safety, stemming from the necessity of water itself as well as the steady stream of income that the stocks here generate. The group as a whole ranks near the top of the Value Line Investment Survey for Timeliness and should continue to do

> well over the next six to 12 months, as investors look for a place to ride out the economic turbulence that is likely to persist.

Mr. Costanza continued to have an upbeat assessment of the water utility industry in the most recent Value Line update published on April 24, 2009:

> Not much has changed in the Water Utility Industry since our October report. Stocks here have held their ground for the most part, whereas the broader market continued to struggle with ongoing economic uncertainty. Although an improving regulatory environment has played a hand, the industry is really benefiting from the its perceived safety, stemming from the necessity of water itself as well as the steady stream of income that the stocks here generate. The group as a whole ranks near the top of the Value Line Investment Survey for Timeliness and should continue to do well over the next six to 12 months, as investors look for a place to ride out the economic turbulence that is likely to persist.

Q. After weighing the economic information that you've just discussed, do you believe that the 8.33 percent cost of equity capital that you have estimated is reasonable for AWC?

A. I believe that my recommended 8.33 percent cost of equity will provide AWC with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are low by historical standards), the current slowdown in growth in new housing construction, and the Fed's ability to keep inflation in check are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my cost of equity analysis, which is an average of the results of both the DCF and CAPM models, has produced such a return.

COST OF DEBT

Q. Have you reviewed AWC's testimony on the Company-proposed cost of long-term debt?

A. Yes.

Q. What cost of long-term debt are you recommending for AWC?

A. I am recommending that the Commission adopt the Company proposed cost of debt of 7.31 percent.

CAPITAL STRUCTURE

Q. Have you reviewed AWC's testimony regarding the Company's proposed capital structure?

A. Yes.

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing a capital structure comprised of 50.76 percent long-term debt and 49.24 percent common equity.

Q. Is AWC's capital structure in line with industry averages?

A. For the most part, yes. As can be seen in Schedule WAR-9, AWC's capital structure is definitely in line with the capital structures of the water utilities in my sample. The capital structures for those utilities averaged 50.4 percent for debt and 49.6 percent for equity. AWC is roughly in line

with the capital structures of the LDC's in my sample. The capital structures for those utilities averaged 45.9 percent for debt and 54.1 percent for equity (53.4 percent common equity + 0.7 percent preferred equity).

Q. What capital structure are you recommending for AWC?

A. I am recommending that the Commission adopt the Company-proposed capital structure comprised of 50.76 percent long-term debt and 49.24 percent common equity.

WEIGHTED COST OF CAPITAL

Q. How does the Company's proposed weighted cost of capital compare with your recommendation?

A. The Company has proposed a weighted cost of capital of 9.81 percent. This figure is the result of a weighted average of AWC's proposed 7.31 percent cost of long-term debt and 12.40 percent cost of common equity capital. The Company-proposed 9.81 percent weighted cost of capital is 200 basis points higher than the 7.81 percent weighted cost of capital that I am recommending.

COMMENTS ON AWC'S COST OF EQUITY CAPITAL TESTIMONY

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The Company's cost of capital witness, Dr. Zepp, is recommending a cost of common equity of 12.40 percent. His 12.40 percent cost of equity capital is 407 basis points higher than the 8.33 percent cost of equity capital that I have calculated.

Q. Briefly summarize Dr. Zepp's direct testimony.

A. Dr. Zepp devotes a large portion of his testimony describing the risks faced by AWC and why the Company's requests for a number pass through adjustor mechanisms is justified. The remainder of his testimony presents the results of his DCF and CAPM analyses.

Q. What methods did Dr. Zepp use to arrive at his cost of common equity for AWC?

A. Dr. Zepp used both the DCF and CAPM methods. His DCF analysis relies on two estimates for the growth component ("g") of the constant model that I also used in my analysis. Dr. Zepp's DCF results range from 11.30 percent to 11.90 percent compared with my DCF average of 10.37 percent. In regard to the CAPM, Dr. Zepp also uses the same Sharpe/Litner version of the CAPM model that I have used. His CAPM

analysis uses two different market risk premium inputs and his results range from 11.80 percent to 12.50 percent compared to my average CAPM result of 6.28 percent.

DCF Comparison

Q. What are the main reasons for the difference in the results that you obtained from your DCF analysis and the results that Dr. Zepp obtained from his DCF analysis using the constant growth model?

A. Dr. Zepp's dividend yields, based on three and twelve months of observed stock price movements, are roughly the same as the results I obtained from my water company sample but are lower than the dividend yields obtained from my sample of LDC's. The main reason for the difference in our DCF results are the growth estimates that Dr. Zepp used in his DCF model. His first growth estimate, which he labels as the "conceptually correct DCF estimates" is 8.81 percent based on a 3-month dividend yield and 8.79 percent based on a 12-month dividend yield. His second growth estimate which, is based on ACC Staff's past approach for calculating a DCF growth component is 8.31 percent based on a 3-month dividend yield and 8.29 percent based on a 12-month dividend yield. On average his growth estimates for the DCF model are 221 basis points higher than the average of my DCF growth estimates.

...

Q. Do you agree with Dr. Zepp's estimates of growth?

A. No. I believe that the main reason for the difference in our earnings estimates is that Dr. Zepp is relying only on earnings per share forecasts as opposed to taking estimates of future growth in earnings, dividends and book value per share into consideration as I have in developing my DCF growth estimates (current Value Line estimates of EPS, DPS and BVPS for the companies included in my water and gas samples can be seen on my Schedule WAR-6). Reliance on earnings per share estimates alone would tend to produce the higher results obtained by Dr. Zepp.

CAPM Comparison

Q. What is the difference between the risk-free instrument that Dr. Zepp used in his CAPM model and the one that you used?

A. Dr. Zepp used forecasted yields on long-term U.S. Treasury instruments as the input for the risk-free rate of return component in the CAPM model. Dr Zepp's average forecasted long-term yield of 4.90 percent is 303 basis points higher than 1.87 percent average yield of the 5-year treasury instrument that I relied on.

Q. What are your concerns with Dr. Zepp's use of forecasted yields on long-term U.S. Treasury instruments for a risk-free rate of return?

A. Besides the fact that Dr. Zepp relied on forecasts as opposed to actual current yields (that result from prices for Treasury instruments that factor in investors' future expectations) I believe that long-term treasury instruments are not as suitable as intermediate-term instruments. As I stated earlier in my testimony a good argument can be made that since utilities in Arizona typically file for rates every three to five years, the yield on a 5-year U.S. Treasury Instrument is a better proxy for a risk-free rate of return.

Q. How did Dr. Zepp's average beta used in his CAPM model compare with the average beta that you used in yours?

A. Dr Zepp's average beta for the water companies in his sample averaged 0.98 as opposed to the average 0.82 beta that I used in my CAPM analysis (which did not rely on three of the water utilities that Dr. Zepp included in his sample) and the average beta of 0.67 that I obtained from my sample of LDC's.

Q. Has the average for the water utilities that Dr. Zepp included in his sample changed since the time his testimony was filed?

A. Yes. The current average beta for the water utilities that Dr. Zepp included in his sample is now 0.84 as opposed to the average beta of 0.98 that he relied on. The updated average would produce a lower expected rate of return in Dr. Zepp's CAPM model.

Q. How does Dr. Zepp's market risk premium compare with the market risk premium that you used in your CAPM analysis?

A. Dr. Zepp relied on two higher market risk premiums which produced an average risk premium of 7.40 percent as opposed to the average market risk premium of 5.95 percent that I used. His market risk premiums were calculated on a narrower range of observed returns as opposed to the range of returns that I relied on.

Q. How did Dr. Zepp arrive at his final 12.40 percent cost of common equity for AWC?

A. Dr. Zepp's final estimate of 12.40 percent is based upon an average of the results of his various DCF and CAPM models. In arriving at final cost of equity figure for AWC, he adds an additional 50 basis points, to take into account the additional risks that Dr. Zepp believes AWC faces.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Dr. Zepp or any other witness for AWC constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on AWC?

A. Yes, it does.

ATTACHMENT A

Water utility stocks have remained relatively trendy in recent months, with investors continuing to flood the industry with cash in an attempt to seek shelter in its traditionally stable fundamentals and hide out from the broader market volatility. Momentum is likely to remain strong for the foreseeable future, as an improving regulatory environment ought to enable the group to post solid earnings growth, despite heightened economic fears.

Meanwhile, the group's long history of steady income provision is another selling point in a time when many outside this realm are being forced to slash payouts. Although the recent decision by *Southwest Water* to reduce its dividend (see page 1798 for details) proves that nobody is immune, the group, as a whole, has a healthy track record of income generation even in the toughest of atmospheres. That said, the industry ranks near the pinnacle of the *Value Line* investment universe, with a handful of timely issues to choose from.

Longer-term, these stocks lose some of their luster, however. Not a single issue in this industry stands out for 3- to 5-year appreciation potential, with burgeoning infrastructure costs expected to repress profit margins over that period.

Flowing Demand Trends

Water is a necessity of life, making it a much sought after commodity. However, the world's fresh water supply is limited, with many experts predicting that reserves in certain areas may begin to dry up sooner than expected. Obviously, water providers are a vital part of the process and stand to benefit going forward.

Also, helping to paint a favorable backdrop, is the recent uptick in support from state regulatory factions. Indeed, although state regulatory authorities were put in place to help maintain a balance of power between customers and providers and to ensure that fair business practices were followed, many have traditionally sided with the public, limiting corporate profitability. Nevertheless, regulators, perhaps realizing the importance of utilities, have done a 180-degree about face and are putting new guidelines in place to make sure that providers are fairly compensated. The California Public Utilities Commission, which oversees business in the Golden State, is the best example of this, with the formerly antagonistic board, handing down more favorable and timely rate decisions in recent memory. It has also enacted mechanisms set forth in the Water Action Plan that ought to reduce outside influences (such as weather) on usage rates and allow companies to be compensated for unforeseen expenses, a methodology which should help generate smoother earnings.

INDUSTRY TIMELINESS: 3 (of 99)

Rising Expense Tides

But, while demand and government backing increases, so too will the costs associated with doing business. Infrastructures are lacking and, in many cases, require serious maintenance. Add to that increasingly stringent EPA regulations, and the costs of upkeep is expected to require hundreds of millions of dollars in investment over the next decade. Unfortunately, many operating in this arena do not have the cash on hand to foot the bill, making heavy financing activity a must. As such, debt and stock issuances will probably be commonplace, diluting shareholder gains. On the other hand, the high costs of doing business, along with weighty barriers of entry for new players, is creating opportunities for some of the larger players willing to forge ahead. M&A activity has been white hot and will likely remain so going forward, in our opinion.

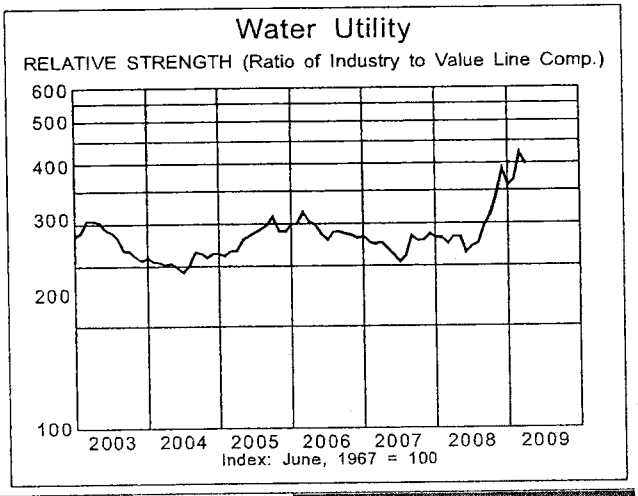
Conclusion

The Water Utility industry looks to be a good a place to be at this juncture. We suspect that the stocks here will be far more stable than the broader market indices, with the aforementioned attributes providing somewhat of an investment safehaven for the coming six to 12 months. Still, we advise investors to review the individual reports of each stock before making a financial commitment. We do urge potential investors to pay particular attention to *American States Water*, whose endeavors into non-regulated military bases may well add to the issue's long-term appeal. *Aqua America*, meanwhile, is interesting based on its aggressive acquisition strategy. That said, we think that investors should keep an eye on *American Water Works*, too. Slightly riskier and unranked because of its short trading history, the stock might well receive a boost if rumors that majority shareholder RWE will liquidate its position pan out.

Andre J. Costanza

Composite Statistics: Water Utility Industry

2005	2006	2007	2008	2009	2010		12-14
1256.9	3454.1	3702.5	*3700*	*4000*	*4250*	Revenues ($mill)	*4775*
148.2	d5.8	d183.0	*350*	*410*	*470*	Net Profit ($mill)	*600*
40.5%	NMF	NMF	*38.0%*	*39.0%*	*40.0%*	Income Tax Rate	*40.0%*
1.1%	NMF	NMF	*5.0%*	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
50.4%	54.0%	51.0%	*52.0%*	*51.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
49.5%	45.9%	49.0%	*48.0%*	*49.0%*	*50.0%*	Common Equity Ratio	*50.0%*
3053.8	12113.9	12985.9	*12325*	*13100*	*13825*	Total Capital ($mill)	*15750*
4200.7	13308.3	14315.2	*14925*	*15750*	*16300*	Net Plant ($mill)	*18725*
6.3%	1.6%	.2%	*4.0%*	*4.5%*	*5.0%*	Return on Total Cap'l	*6.5%*
9.8%	NMF	NMF	*6.0%*	*6.5%*	*7.0%*	Return on Shr. Equity	*7.5%*
9.8%	NMF	NMF	*6.0%*	*6.5%*	*7.0%*	Return on Com Equity	*7.5%*
3.7%	NMF	NMF	*3.0%*	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
62%	NMF	NMF	*50%*	*60%*	*60%*	All Div'ds to Net Prof	*57%*
29.4	NMF	NMF				Avg Ann'l P/E Ratio	*18.5*
1.57	NMF	NMF		*Bold figures are Value Line estimates*		Relative P/E Ratio	*1.20*
2.1%	2.0%	2.3%				Avg Ann'l Div'd Yield	*2.0%*



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AMER. STATES WATER NYSE-AWR

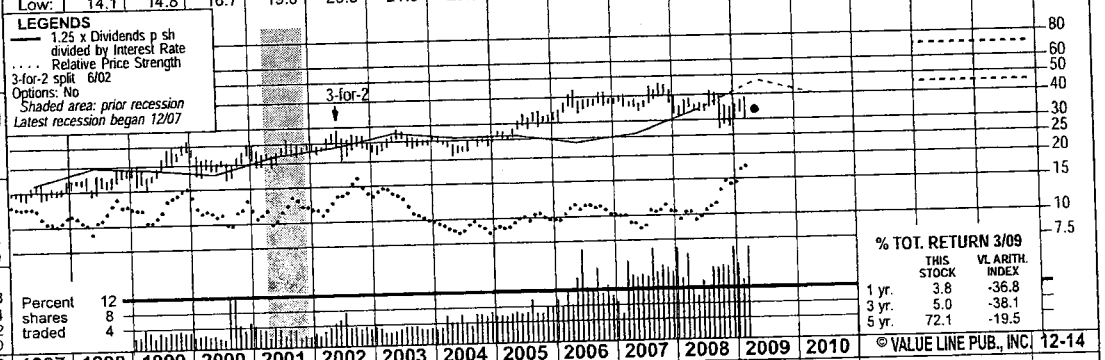
RECENT PRICE 33.62 | P/E RATIO 19.0 (Trailing: 22.1 / Median: 22.0) | RELATIVE P/E RATIO 1.46 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 2 Raised 3/20/09
SAFETY 3 New 2/4/00
TECHNICAL 2 Raised 3/13/09
BETA .85 (1.00 = Market)

High:	19.5	26.5	25.3	26.4	29.0	29.0	26.8	34.6	43.8	46.1	42.0	38.8
Low:	14.1	14.8	16.7	19.0	20.3	21.6	20.8	24.3	30.3	33.6	27.0	29.8

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 6/02
Options: No
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+110%)	22%
Low	45	(+35%)	10%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	2	0	0	0	0	0	0	0
Options	1	0	0	3	0	0	0	0	0
to Sell	1	0	0	3	0	0	1	2	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	59	48	64
to Sell	50	54	52
Hld's(000)	10177	9411	8980

% TOT. RETURN 3/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	3.8	-36.8
3 yr.	5.0	-38.1
5 yr.	72.1	-19.5

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
9.27	10.43	11.03	11.37	11.44	11.02	12.91	12.17	13.06	13.78	13.98	13.61	14.06	15.76	17.49	18.42	*18.35*	*19.20*	Revenues per sh	*21.50*
1.67	1.68	1.75	1.75	1.85	2.04	2.26	2.20	2.53	2.54	2.08	2.23	2.64	2.89	3.31	3.37	*3.60*	*3.80*	"Cash Flow" per sh	*4.60*
1.11	.95	1.03	1.13	1.04	1.08	1.19	1.28	1.35	1.34	.78	1.05	1.32	1.33	1.62	1.55	*1.80*	*1.95*	Earnings per sh A	*2.60*
.79	.80	.81	.82	.83	.84	.85	.86	.87	.87	.88	.89	.90	.91	.96	1.00	*1.06*	*1.08*	Div'd Decl'd per sh B■	*1.28*
1.90	2.43	2.19	2.40	2.58	3.11	4.30	3.03	3.18	2.68	3.76	5.03	4.24	3.91	2.89	4.45	*4.25*	*4.30*	Cap'l Spending per sh	*4.50*
9.95	10.07	10.29	11.01	11.24	11.48	11.82	12.74	13.22	14.05	13.97	15.01	15.72	16.64	17.53	17.95	*18.90*	*19.45*	Book Value per sh	*21.00*
11.71	11.77	11.77	13.33	13.44	13.44	13.44	15.12	15.12	15.18	15.21	16.75	16.80	17.05	17.23	17.30	*18.25*	*18.75*	Common Shs Outst'g C	*20.25*
13.4	12.8	11.6	12.6	14.5	15.5	17.1	15.9	16.7	18.3	31.9	23.2	21.9	27.7	24.0	22.6	*Bold figures are*		Avg Ann'l P/E Ratio	*22.0*
.79	.84	.78	.79	.84	.81	.97	1.03	.86	1.00	1.82	1.23	1.17	1.50	1.27	1.37	*Value Line*		Relative P/E Ratio	*1.45*
5.3%	6.6%	6.7%	5.8%	5.5%	5.0%	4.2%	4.2%	3.9%	3.6%	3.5%	3.6%	3.1%	2.5%	2.5%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*2.2%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $341.8 mill. Due in 5 Yrs $12.4 mill.
LT Debt $266.5 mill. LT Interest $20.0 mill.
(LT interest earned: 3.2x: total interest coverage: 3.0x) (46% of Cap'l)

Leases, Uncapitalized: Annual rentals $2.9 mill.
Pension Assets-12/08 $54.2 mill.
Oblig. $94.5 mill.
Pfd Stock None.

Common Stock 17,301,047 shs.
MARKET CAP: $575 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
173.4	184.0	197.5	209.2	212.7	228.0	236.2	268.6	301.4	318.7	*335*	*360*	Revenues ($mill)	*435*
16.1	18.0	20.4	20.3	11.9	16.5	22.5	23.1	28.0	26.8	*33.0*	*37.0*	Net Profit ($mill)	*53.0*
46.0%	45.7%	43.0%	38.9%	43.5%	37.4%	47.0%	40.5%	42.6%	37.8%	*39.5%*	*40.0%*	Income Tax Rate	*40.0%*
--	--	--	--	--	--	--	12.2%	8.5%	6.9%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
51.0%	47.5%	54.9%	52.0%	52.0%	47.7%	50.4%	48.6%	46.9%	46.2%	*43.5%*	*46.5%*	Long-Term Debt Ratio	*45.5%*
48.4%	51.9%	44.7%	48.0%	48.0%	52.3%	49.6%	51.4%	53.1%	53.8%	*56.5%*	*53.5%*	Common Equity Ratio	*54.5%*
328.2	371.1	447.6	444.4	442.3	480.4	532.5	551.6	569.4	577.0	*610*	*680*	Total Capital ($mill)	*825*
449.6	509.1	539.8	563.3	602.3	664.2	713.2	750.6	776.4	825.3	*870*	*915*	Net Plant ($mill)	*1025*
6.6%	6.4%	6.1%	6.5%	4.6%	5.2%	5.4%	6.0%	6.7%	6.4%	*7.0%*	*7.5%*	Return on Total Cap'l	*9.0%*
10.0%	9.2%	10.1%	9.5%	5.6%	6.6%	8.5%	8.1%	9.3%	8.6%	*9.5%*	*10.0%*	Return on Shr. Equity	*12.5%*
10.1%	9.3%	10.1%	9.5%	5.6%	6.6%	8.5%	8.1%	9.3%	8.6%	*9.5%*	*10.0%*	Return on Com Equity	*12.5%*
2.9%	3.0%	3.6%	3.3%	NMF	1.0%	2.8%	2.7%	3.9%	3.1%	*4.0%*	*4.5%*	Retained to Com Eq	*6.5%*
72%	68%	65%	65%	113%	84%	67%	67%	58%	64%	*59%*	*56%*	All Div'ds to Net Prof	*48%*

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	3.2	1.7	7.3
Receivables	14.8	16.1	14.3
Inventory (Avg Cst)	1.6	1.6	2.1
Other	44.8	43.7	66.9
Current Assets	64.4	63.1	90.6
Accts Payable	24.0	29.1	36.6
Debt Due	32.6	37.8	75.3
Other	29.3	27.4	25.5
Current Liab.	85.9	94.3	137.4
Fix. Chg. Cov.	268%	314%	293%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	4.5%	5.0%	*4.0%*
"Cash Flow"	5.5%	6.0%	*6.5%*
Earnings	3.5%	5.5%	*9.5%*
Dividends	1.5%	2.0%	*5.0%*
Book Value	4.5%	5.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2006	64.3	63.0	75.0	66.3	268.6
2007	72.3	79.3	75.8	74.0	301.4
2008	68.9	80.3	85.3	84.2	318.7
2009	*72.0*	*84.0*	*90.0*	*89.0*	*335*
2010	*78.0*	*90.0*	*96.0*	*96.0*	*360*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2006	.35	.36	.32	.30	1.33
2007	.40	.42	.44	.35	1.62
2008	.30	.53	.26	.43	1.55
2009	*.32*	*.55*	*.47*	*.46*	*1.80*
2010	*.35*	*.59*	*.51*	*.50*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.225	.225	.225	.225	.90
2006	.225	.225	.225	.235	.91
2007	.235	.235	.235	.250	.96
2008	.250	.250	.250	.250	1.00
2009	.250				

BUSINESS: American States Water Co. operates as a holding company. Through its principal subsidiary, Golden State Water Company, it supplies water to more than 250,000 customers in 75 communities in 10 counties. Service areas include the greater metropolitan areas of Los Angeles and Orange Counties. The company also provides electric utility services to nearly 23,250 customers in the city of Big Bear Lake and in areas of San Bernardino County. Acquired Chaparral City Water of Arizona (10/00). Has roughly 675 employees. Officers & directors own 2.5% of common stock (4/08 Proxy). Chairman: Lloyd Ross. President & CEO: Floyd Wicks. Inc: CA. Addr.: 630 East Foothill Boulevard, San Dimas, CA 91773. Tele.: 909-394-3600. Internet: www.aswater.com.

American States Water's non-regulated franchise helped it close out 2008 in impressive fashion. Although the water utility provider's core business was hampered by conservation efforts in the Golden State and increased expenses, continued penetration onto military bases (which are not as heavily regulated) enabled it to post earnings of $0.43 a share in the fourth quarter, 23% better than the year before. Construction activity was especially strong, as pipelines are still being installed at some recently added locations. Total revenues improved 14%, to $84 million.

Its traditional business stands to improve this year. Historically a foe, the state regulatory body, the California Public Utilities Commission (CPUC), appears to have come around, adopting a more business-friendly approach and methodology that provides utilities with the means to mitigate the risks of weather fluctuations and the effects on water consumption. Specifically, the board implemented the water revenue adjustment mechanism (WRAM) and a modified cost balancing accounting (MCBA) principal that will enable American to recoup lost wages and production costs not anticipated in general rate case decisions. Adopted in late November, WRAM and MCBA should help to stabilize costs and produce smoother earnings growth. In all, we are forecasting that the company will earn $1.80 a share, on $335 million in revenues in 2009.

Additional relief will likely come next year. The company is awaiting a ruling on its 2008 general rate case for regions II and III, requesting an increase north of $50 million. If approved, the new rates are to go into effect in January, 2010. The CPUC's recent rulings leave us optimistic.

The stock is ranked 2 (Above Average) for Timeliness . . . We expect AWR to continue outpacing the broader market over the coming six to 12 months.

. . . but is not for everyone. Although the steady stream of income may pique the interest of investors looking to steer clear of the recent market volatility, we suspect that the financing that will be required to keep up with anticipated burgeoning infrastructure costs will limit 3- to 5-year shareholder gains.

Andre J. Costanza *April 24, 2009*

(A) Primary earnings. Excludes nonrecurring gains/(losses): '91, 73¢; '92, 13¢; '04, 14¢; '05, 25¢; '06, 6¢; '08, (27¢). Next earnings report due early May. May not add due to rounding.

(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for splits.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	75
Earnings Predictability	65

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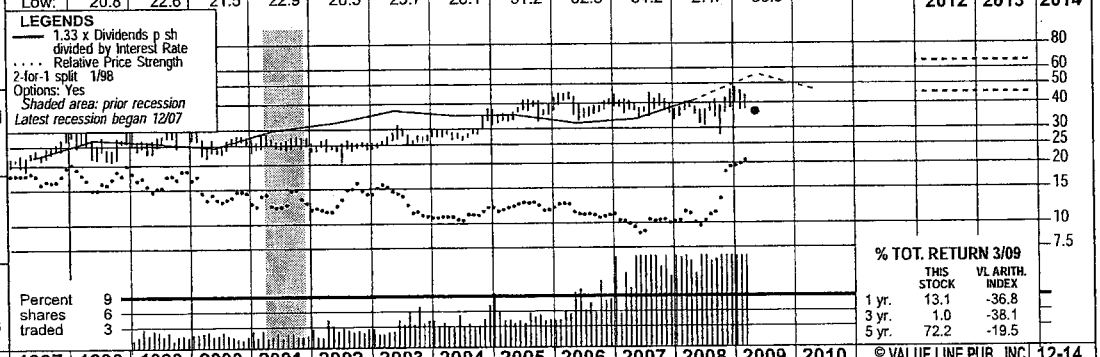
CALIFORNIA WATER NYSE-CWT

RECENT PRICE 36.35 | P/E RATIO 18.1 (Trailing: 19.1 Median: 22.0) | RELATIVE P/E RATIO 1.39 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 2 Raised 11/7/08
SAFETY 3 Lowered 7/27/07
TECHNICAL 1 Raised 4/24/09
BETA .85 (1.00 = Market)

High:	33.8	32.0	31.4	28.6	26.9	31.4	37.9	42.1	45.8	45.4	46.6	48.3	
Low:	20.8	22.6	21.5	22.9	20.5	23.7	26.1	31.2	32.8	34.2	27.7	36.3	

Target Price Range 2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+80%)	18%
Low	45	(+25%)	9%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	65	49	107
to Sell	45	58	46
Hld's(000)	9849	9891	9799

% TOT. RETURN 3/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	13.1	-36.8
3 yr.	1.0	-38.1
5 yr.	72.2	-19.5

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
13.34	12.59	13.17	14.48	15.48	14.76	15.96	16.16	16.26	17.33	16.37	17.18	17.44	16.20	17.76	19.80	21.20	22.10	Revenues per sh	24.45
2.25	2.02	2.07	2.50	2.92	2.60	2.75	2.52	2.20	2.65	2.51	2.83	3.03	2.71	3.12	3.72	3.95	4.10	"Cash Flow" per sh	4.65
1.35	1.22	1.17	1.51	1.83	1.45	1.53	1.31	.94	1.25	1.21	1.46	1.47	1.34	1.50	1.90	2.05	2.15	Earnings per sh A	2.65
.96	.99	1.02	1.04	1.06	1.07	1.09	1.10	1.12	1.12	1.12	1.13	1.14	1.15	1.16	1.17	1.18	1.19	Div'd Decl'd per sh B ■	1.34
2.53	2.26	2.17	2.83	2.61	2.74	3.44	2.45	4.09	5.82	4.39	3.73	4.01	4.28	3.68	4.82	4.75	4.80	Cap'l Spending per sh	5.00
10.90	11.56	11.72	12.22	13.00	13.38	13.43	12.90	12.95	13.12	14.44	15.66	15.79	18.15	18.50	19.44	19.90	20.60	Book Value per sh C	22.20
11.38	12.49	12.54	12.62	12.62	12.62	12.94	15.15	15.18	15.18	16.93	18.37	18.39	20.66	20.67	20.72	21.00	21.25	Common Shs Outst'g D	22.50
13.6	14.1	13.7	11.9	12.6	17.8	17.8	19.6	27.1	19.8	22.1	20.1	24.9	29.2	26.1	19.8	Bold figures are		Avg Ann'l P/E Ratio	21.0
.80	.92	.92	.75	.73	.93	1.01	1.27	1.39	1.08	1.26	1.06	1.33	1.58	1.39	1.20	Value Line		Relative P/E Ratio	1.40
5.2%	5.8%	6.4%	5.8%	4.6%	4.2%	4.0%	4.3%	4.4%	4.5%	4.2%	3.9%	3.1%	2.9%	3.0%	3.1%	estimates		Avg Ann'l Div'd Yield	2.4%
						206.4	244.8	246.8	263.2	277.1	315.6	320.7	334.7	367.1	410.3	445	470	Revenues ($mill)	550
						19.9	20.0	14.4	19.1	19.4	26.0	27.2	25.6	31.2	39.8	43.0	46.0	Net Profit ($mill)	60.0
						37.9%	42.3%	39.4%	39.7%	39.9%	39.6%	42.4%	37.4%	39.9%	37.7%	38.0%	38.5%	Income Tax Rate	39.0%
						--	--	--	--	10.3%	3.2%	3.3%	10.6%	8.3%	8.6%	8.5%	8.5%	AFUDC % to Net Profit	8.5%
						46.9%	48.9%	50.3%	55.3%	50.2%	48.6%	48.3%	43.5%	42.9%	41.6%	48.0%	47.5%	Long-Term Debt Ratio	45.0%
						52.0%	50.2%	48.8%	44.0%	49.1%	50.8%	51.1%	55.9%	56.6%	58.4%	52.0%	52.5%	Common Equity Ratio	55.0%
						333.8	388.8	402.7	453.1	498.4	565.9	568.1	670.1	674.9	690.4	805	835	Total Capital ($mill)	950
						515.4	582.0	624.3	697.0	759.5	800.3	862.7	941.5	1010.2	1112.4	1175	1235	Net Plant ($mill)	1425
						7.8%	6.8%	5.3%	5.9%	5.6%	6.1%	6.3%	5.2%	5.9%	7.1%	7.0%	7.0%	Return on Total Cap'l	8.0%
						11.2%	10.0%	7.2%	9.4%	7.8%	8.9%	9.3%	6.8%	8.1%	9.9%	10.5%	10.5%	Return on Shr. Equity	12.0%
						11.4%	10.1%	7.2%	9.5%	7.9%	9.0%	9.3%	6.8%	8.1%	9.9%	10.5%	10.5%	Return on Com Equity	12.0%
						3.5%	1.8%	NMF	1.0%	.7%	2.1%	2.1%	1.0%	1.8%	3.8%	4.5%	4.5%	Retained to Com Eq	6.0%
						70%	82%	119%	90%	91%	77%	78%	86%	77%	61%	58%	55%	All Div'ds to Net Prof	50%

CAPITAL STRUCTURE as of 12/31/08
Total Debt $330.3 mill. Due in 5 Yrs $70.9 mill.
LT Debt $287.5 mill. LT Interest $20.6 mill.

(LT interest earned: 4.4x; total int. cov.: 4.1x)

Pension Assets-12/08 $66.9 mill. Oblig. $192.9 mill.

Pfd Stock None

Common Stock 20,723,952 shs. as of 2/23/09

MARKET CAP: $750 million (Small Cap)

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	60.3	6.7	13.9
Other	49.3	53.3	65.9
Current Assets	109.6	60.0	79.8
Accts Payable	33.1	36.7	41.8
Debt Due	1.8	2.7	42.8
Other	35.3	30.3	35.8
Current Liab.	70.2	69.7	123.2
Fix. Chg. Cov.	290%	333%	398%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	2.0%	1.5%	5.5%
"Cash Flow"	2.0%	5.5%	6.5%
Earnings	--	7.0%	9.0%
Dividends	1.0%	0.5%	2.5%
Book Value	4.0%	6.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	65.2	81.1	107.8	80.6	334.7
2007	71.6	95.8	113.8	85.9	367.1
2008	72.9	105.6	131.7	100.1	410.3
2009	80.0	115	140	110	445
2010	85.0	120	150	115	470

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.04	.31	.68	.31	1.34
2007	.07	.37	.67	.39	1.50
2008	.01	.48	1.06	.35	1.90
2009	.08	.53	1.05	.39	2.05
2010	.10	.55	1.10	.40	2.15

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.285	.285	.285	.285	1.14
2006	.2875	.2875	.2875	.2875	1.15
2007	.290	.290	.290	.290	1.16
2008	.293	.293	.293	.293	1.17
2009	.295				

BUSINESS: California Water Service Group provides regulated and nonregulated water service to roughly 463,600 customers in 83 communities in California, Washington, New Mexico, and Hawaii. Main service areas: San Francisco Bay area, Sacramento Valley, Salinas Valley, San Joaquin Valley & parts of Los Angeles. Acquired Rio Grande Corp; West Hawaii Utilities (9/08). Revenue breakdown, '08: residential, 69%; business, 18%; public authorities, 5%; industrial, 5%; other, 3%. '08 reported depreciation rate: 2.4%. Has roughly 929 employees. Chairman: Robert W. Foy. President & CEO: Peter C. Nelson (4/09 Proxy). Inc.: Delaware. Address: 1720 North First Street, San Jose, California 95112-4598. Telephone: 408-367-8200. Internet: www.calwatergroup.com.

California Water Service Group ran into some unforeseen problems in the final quarter of 2008. Although recent regulatory rulings helped the water utility provider post a handsome 16% top-line advance, production and maintenance costs ballooned. As a result, earnings disappointed, coming in 20% below our estimate and 10% off last year's mark.

We look for earnings growth to resume this year, however, to the tune of roughly 8%. The regulatory environment has evolved greatly in recent months, with the California Public Utilities Commission (CPUC) implementing a rate increase on the company's 2007 general rate case, which should add $47 million to the ledger annually. Meanwhile, the board also instituted a water revenue adjustment mechanism (WRAM) as well as a modified cost-balancing accounting principle (MCBA). WRAM basically decouples sales from revenues, enables utilities to recover wages below rates adopted in general rate assumptions, while the MCBA component allows for the recovery of production costs, such as purchased water. We look for the company to earn $2.05 a share, on $445 million in revenues, with the new procedures in place.

Wall Street was not happy with the latest earnings miss . . . CWT has sunk nearly 10% since our January report.

. . . but the stock remains favorably ranked (2: Above Average) for Timeliness. The adoption of the WRAM and MCBA principles are expected to provide smoother, more predictable earnings growth going forward, which ought to appeal to investors seeking shelter from the turbulent market environment. Likewise, CWT's steady dividend is a boon.

Nevertheless, the issue holds limited 3- to 5-year appreciation potential. Water distribution is a capital-intense business, with aging infrastructures and growing EPA requirements facilitating heavy investments that the company is currently ill equipped to meet. Equity and debt issuances will likely remain commonplace, such as the $100 million bond offering that management intends to unveil. Indeed, the increased financing costs are likely to keep bottom-line growth under wraps for the foreseeable future.

Andre J. Costanza *April 24, 2009*

(A) Basic EPS. Excl. nonrecurring gain (loss): '00, (7¢); '01, 4¢; '02, 8¢. Next earnings report due early May.
(B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.
(C) Incl. deferred charges. In '08: $3.9 mill., $.19/sh.
(D) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	70
Earnings Predictability	75

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AQUA AMERICA NYSE-WTR

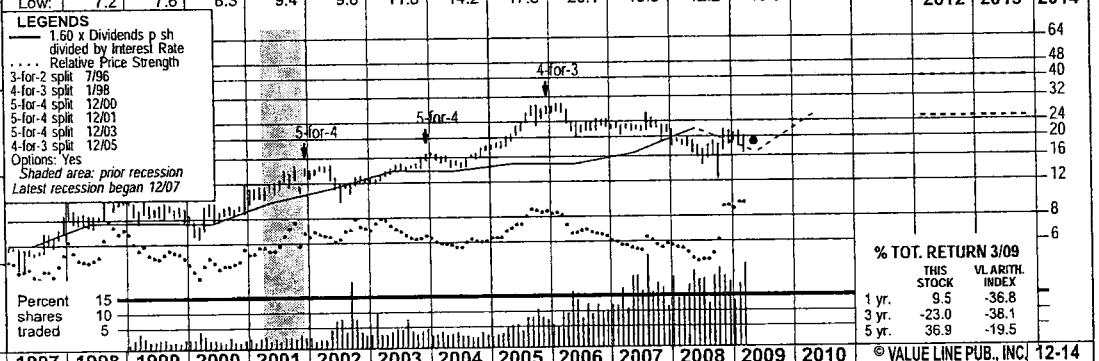
RECENT PRICE 18.93 | P/E RATIO 24.0 (Trailing: 25.9 / Median: 25.0) | RELATIVE P/E RATIO 1.85 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 2 Raised 11/14/08
SAFETY 3 Lowered 8/1/03
TECHNICAL 1 Raised 4/24/09
BETA .75 (1.00 = Market)

High:	11.5	11.5	12.0	14.8	15.0	16.8	18.5	29.2	29.8	26.6	22.0	21.5
Low:	7.2	7.6	6.3	9.4	9.6	11.8	14.2	17.5	20.1	18.9	12.2	16.6

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.60 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 7/96
4-for-3 split 1/98
5-for-4 split 12/00
5-for-4 split 12/01
5-for-4 split 12/03
4-for-3 split 12/05
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+110%)	22%
Low	25	(+30%)	10%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	0	0	0	0	1	0
to Sell	1	0	0	0	0	0	0	1	0

Institutional Decisions

	2Q2008	3Q2008	4Q2008
to Buy	115	103	131
to Sell	111	108	131
Hld's(000)	66368	62150	60996

% TOT. RETURN 3/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	9.5	-36.8
3 yr.	-23.0	-38.1
5 yr.	36.9	-19.5

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
1.70	1.82	1.84	1.86	2.02	2.09	2.41	2.46	2.70	2.85	2.97	3.48	3.85	4.03	4.52	4.63	*4.95*	*5.30*	Revenues per sh	*6.50*
.42	.42	.47	.50	.56	.61	.72	.76	.86	.94	.96	1.09	1.21	1.26	1.37	1.42	*1.55*	*1.65*	"Cash Flow" per sh	*2.10*
.24	.26	.29	.30	.34	.40	.42	.47	.51	.54	.57	.64	.71	.70	.71	.73	*.80*	*.90*	Earnings per sh A	*1.25*
.21	.21	.22	.23	.24	.26	.27	.28	.30	.32	.35	.37	.40	.44	.48	.51	*.54*	*.56*	Div'd Decl'd per sh B■	*.62*
.47	.46	.52	.48	.58	.82	.90	1.16	1.09	1.20	1.32	1.54	1.84	2.05	1.79	1.98	*2.05*	*2.10*	Cap'l Spending per sh	*2.15*
2.29	2.41	2.46	2.69	2.84	3.21	3.42	3.85	4.15	4.36	5.34	5.89	6.30	6.96	7.32	7.82	*8.15*	*8.55*	Book Value per sh	*10.60*
59.40	59.77	63.74	65.75	67.47	72.20	106.80	111.82	113.97	113.19	123.45	127.18	128.97	132.33	133.40	135.37	*136.00*	*136.50*	Common Shs Outst'g C	*138.00*
14.4	13.5	12.0	15.6	17.8	22.5	21.2	18.2	23.6	23.6	24.5	25.1	31.8	34.7	32.0	24.9	*Bold figures are*		Avg Ann'l P/E Ratio	*25.0*
.85	.89	.80	.98	1.03	1.17	1.21	1.18	1.21	1.29	1.40	1.33	1.69	1.87	1.70	1.51	*Value Line*		Relative P/E Ratio	*1.65*
5.9%	6.0%	6.2%	4.9%	3.9%	2.9%	3.0%	3.3%	2.5%	2.5%	2.5%	2.3%	1.8%	1.8%	2.1%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*1.9%*
						257.3	275.5	307.3	322.0	367.2	442.0	496.8	533.5	602.5	627.0	*675*	*725*	Revenues ($mill)	*900*
						45.0	50.7	58.5	62.7	67.3	80.0	91.2	92.0	95.0	97.9	*110*	*125*	Net Profit ($mill)	*170*
						38.4%	38.9%	39.3%	38.5%	39.3%	39.4%	38.4%	39.6%	38.9%	39.7%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
						--	--	--	--	--	--	--	--	2.9%	3.1%	*3.5%*	*3.2%*	AFUDC % to Net Profit	*2.5%*
						52.9%	52.0%	52.2%	54.2%	51.4%	50.0%	52.0%	51.6%	55.4%	54.1%	*53.5%*	*52.5%*	Long-Term Debt Ratio	*49.0%*
						46.7%	47.8%	47.7%	45.8%	48.6%	50.0%	48.0%	48.4%	44.6%	45.9%	*46.5%*	*47.5%*	Common Equity Ratio	*51.0%*
						782.7	901.1	990.4	1076.2	1355.7	1497.3	1690.4	1904.4	2191.4	2306.6	*2385*	*2470*	Total Capital ($mill)	*2865*
						1135.4	1251.4	1368.1	1490.8	1824.3	2069.8	2280.0	2506.0	2792.8	2997.4	*3150*	*3300*	Net Plant ($mill)	*3600*
						7.6%	7.4%	7.8%	7.6%	6.4%	6.7%	6.9%	6.4%	5.9%	5.7%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
						12.2%	11.7%	12.3%	12.7%	10.2%	10.7%	11.2%	10.0%	9.7%	9.3%	*10.0%*	*10.5%*	Return on Shr. Equity	*11.5%*
						12.3%	11.7%	12.4%	12.7%	10.2%	10.7%	11.2%	10.0%	9.7%	9.3%	*10.0%*	*10.5%*	Return on Com Equity	*11.5%*
						4.3%	4.7%	5.1%	5.2%	4.2%	4.6%	4.9%	3.7%	3.2%	2.8%	*2.5%*	*3.0%*	Retained to Com Eq	*5.0%*
						65%	60%	59%	59%	59%	57%	56%	63%	67%	70%	*67%*	*60%*	All Div'ds to Net Prof	*47%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $1336.0 mill. **Due in 5 Yrs** $243.9 mill.
LT Debt $1248.1 mill. **LT Interest** $65.0 mill.
(LT interest earned: 3.4x; total interest coverage: 3.4x) (54% of Cap'l)

Pension Assets-12/08 $112.2 mill. **Oblig.** $204.7 mill.

Pfd Stock None
Common Stock 135,413,407 shares as of 2/10/09

MARKET CAP: $2.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	44.0	14.5	14.9
Receivables	72.1	82.9	84.5
Inventory (AvgCst)	10.2	8.8	9.8
Other	8.4	9.3	11.8
Current Assets	134.7	115.5	121.0
Accts Payable	49.4	45.8	50.0
Debt Due	150.4	80.8	87.9
Other	55.8	56.6	55.3
Current Liab.	255.6	183.2	193.2
Fix. Chg. Cov.	352%	323%	329%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.0%	9.0%	*6.5%*
"Cash Flow"	9.5%	8.0%	*7.5%*
Earnings	7.5%	5.5%	*10.0%*
Dividends	7.0%	8.0%	*3.5%*
Book Value	9.5%	10.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	117.9	131.7	147.0	136.9	533.5
2007	137.3	150.6	165.5	149.1	602.5
2008	139.3	151.0	177.1	159.6	627.0
2009	*150*	*160*	*190*	*175*	*675*
2010	*160*	*175*	*205*	*185*	*725*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.13	.17	.21	.19	.70
2007	.13	.17	.22	.19	.71
2008	.11	.17	.26	.19	.73
2009	*.13*	*.19*	*.28*	*.20*	*.80*
2010	*.15*	*.22*	*.30*	*.23*	*.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.098	.098	.098	.107	.40
2006	.107	.107	.115	.115	.44
2007	.115	.115	.125	.125	.48
2008	.125	.125	.125	.135	.51
2009	.135				

BUSINESS: Aqua America, Inc. is the holding company for water and wastewater utilities that serve approximately 2.8 million residents in Pennsylvania, Ohio, North Carolina, Illinois, Texas, New Jersey, Florida, Indiana, and five other states. Divested three of four non-water businesses in '91; telemarketing group in '93; and others. Acquired AquaSource, 7/03; Consumers Water, 4/99; and others. Water supply revenues '08: residential, 60%; commercial, 14%; industrial & other, 26%. Officers and directors own 1.3% of the common stock (4/09 Proxy). Chairman & Chief Executive Officer: Nicholas DeBenedictis. Incorporated: Pennsylvania. Address: 762 West Lancaster Avenue, Bryn Mawr, Pennsylvania 19010. Telephone: 610-525-1400. Internet: www.aquaamerica.com.

Aqua America completed 2008 on a solid note. On a year-over-year comparative basis, revenues increased 4% and earnings advanced 3%. These gains were mostly due to customers obtained through acquisitions, and successful court-mandated rate-increase adjustments. Offsetting some of these gains were rising costs for chemicals and fuel during the year, and increased outlays for pipe repair, most of which occurred during the fourth quarter. Still, by divesting underperforming assets in Virginia and Texas, management was able to mitigate the impact of the cost increases.

The company should be able to build on this momentum in 2009. Indeed, several rate-relief cases should be decided over the coming months, and should add $15 million–$20 million to the top line toward the latter half of the year if decided in Aqua America's favor. Additional rate increase petitions for upwards of $70 million will also be filed during the year. Too, there will likely be further acquisitions, as the company's growth strategy includes purchasing available utilities and making infrastructure improvements in order to obtain rate relief judgments. This should benefit the company's cost structure and broaden its customer base. Expenses should also moderate as costs for fuel and chemicals have leveled recently.

We are instituting top- and bottom-line estimates of $725 million and $0.90 for 2010. With the majority of its rate cases uncontested, the average nine-month turnaround for rate relief decisions should begin to add to sales and earnings in early 2010. These price increases should offset the higher capital expenditures that are likely to occur, as Aqua continues to purchase plants that it believes will be profitable after the company's infrastructure improvements have been made.

These shares are ranked Above Average (2) for Timeliness, but most of the gains we project over the coming 3- to 5-year stretch are already discounted in the current quotation. However, this stock has a steady, though unexciting, dividend yield, and while it holds an Average (3) rank for Safety, it's high scores for Earnings Predictability and Price Stability should appeal to conservative investors.

John D. Burke *April 24, 2009*

(A) Primary shares outstanding through '96; diluted thereafter. Excl. nonrec. gains (losses): '92, (38¢); '99, (11¢); '00, 2¢; '01, 2¢; '02, 5¢; '03, 4¢. Excl. gain from disc. operations: '96, 2¢. Next earnings report due early May.
(B) Dividends historically paid in early March, June, Sept. & Dec. ■ Div'd. reinvestment plan available (5% discount).
(C) In millions, adjusted for stock splits.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	100

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ATTACHMENT B

INDUSTRY TIMELINESS: 5 (of 99)

The Natural Gas Utility Industry has performed well in recent months. This is impressive given the weak economy and a tough regulatory environment. Despite these challenges, companies in this sector continue to deliver solid results and represent a relatively safe option amid the turmoil in the world's financial markets. As a result, this group has risen near the top of our industry spectrum.

Economic Environment

The global economy continues to struggle. Tight credit and a slumping real estate market are among the main factors contributing to the recessionary environment. Furthermore, these conditions continue to weigh on results in this sector. Indeed, usage continues to decline as customers have become more cost conscious. Moreover, bill collection has become increasingly difficult as unemployment and foreclosures continue to rise. Despite the aforementioned conditions, investors should note that this group is an interesting defensive play. While these factors will likely continue to impact the utilities, this industry should perform well compared to the rest of the market in the months ahead. Natural Gas Utilities generally have solid balance sheets and predictable cash flows, which is appealing given the weakness in the economy.

Regulation

This group is regulated by state commissions that dictate the return on equity these utilities can achieve. Consequently, the regulatory environment has a heavy bearing on each individual company's results. If a utility does not have ample relief, its budget can become strained. As a result, a company's infrastructure can age and profitability can decline. On the other hand, a favorable ruling can position a utility to register steady gains and allow it to build its infrastructure. Therefore, rate cases remain the main theme in this sector. On point, numerous companies currently have rate cases pending. *Southwest Gas, Nicor, AGL Resources* are all awaiting decisions, which should drive their performance going forward. Moreover, energy efficiency will likely become an increasingly important factor in these decisions given the new administration in the White House. As the United States moves in this direction, utilities that embrace energy conservation measures may benefit from a more favorable regulatory environment.

Nonregulated Ventures

A strategy that is becoming increasingly common is nonregulated ventures. These opportunities allow companies to diversify their operations and gain income that is not subject to the state regulatory commissions. These businesses currently make up only a small portion of this sector's profits but will likely become a more important opportunity in the years ahead.

Weather

The peak heating season is just about coming to an end. This period is when these utilities have their best opportunity to post strong results on the bottom line. Looking ahead, these companies will likely turn their attention to strengthening their operations and better managing their costs as we move toward the summer months.

Weather abnormalities can hurt results. Many of these businesses have weather-adjusted rate mechanisms that are used to hedge the risk of unseasonable weather. Thus, investors should keep an eye out for utilities that rely on this strategy since they usually have a relatively steady performance.

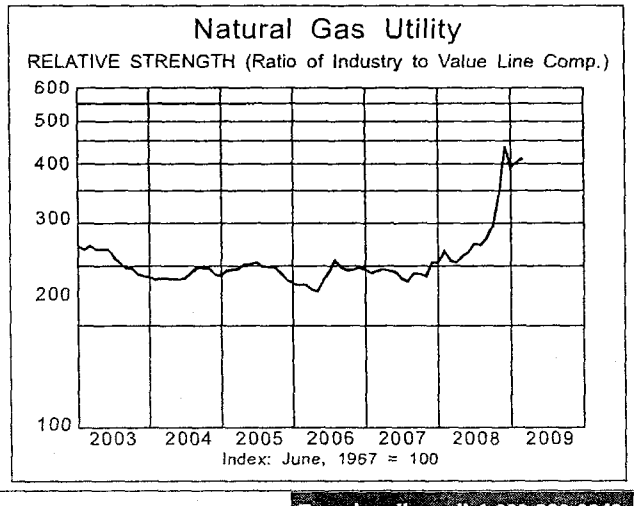
Conclusion

The Natural Gas Utility sector has climbed near the top of our industry spectrum in recent months. Indeed, it features numerous timely stocks. In fact, *UGI* holds our highest rank (1) for Timeliness. However, various other companies are ranked to outperform the market over the coming six to 12 months. What's more, the majority of the equities in this industry offer above-average yields. Most notably, *Nicor, AGL Resources* and *Atmos Energy* all offer attractive payouts supported by steady cash flows. Therefore, investors looking for a good play in the year ahead should consider some of the names in this group.

Richard Gallagher

Composite Statistics: Natural Gas Utility

2005	2006	2007	2008	2009	2010		12-14
36075	38273	38528	*40000*	*41500*	*42750*	Revenues ($mill)	*51250*
1386.0	1553.3	1562.4	*1650*	*1725*	*1800*	Net Profit ($mill)	*2150*
36.0%	35.3%	33.9%	*36.0%*	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
3.8%	4.0%	4.1%	*4.1%*	*4.2%*	*4.2%*	Net Profit Margin	*4.2%*
51.3%	51.2%	50.4%	*51.0%*	*51.0%*	*51.0%*	Long-Term Debt Ratio	*52.0%*
48.4%	48.7%	49.5%	*48.0%*	*48.0%*	*48.0%*	Common Equity Ratio	*46.0%*
29218	30847	32263	*33750*	*33250*	*34750*	Total Capital ($mill)	*40000*
30894	32543	33936	*35250*	*36750*	*38500*	Net Plant ($mill)	*46250*
6.5%	6.6%	6.5%	*6.5%*	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
9.7%	10.2%	9.8%	*10.0%*	*10.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.8%	10.2%	9.8%	*10.0%*	*10.0%*	*10.5%*	Return on Com Equity	*11.0%*
3.5%	4.0%	3.7%	*4.0%*	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
65%	61%	62%	*63%*	*63%*	*64%*	All Div'ds to Net Prof	*65%*
17.1	15.6	16.6		*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.91	.84	.88		*Value Line*		Relative P/E Ratio	*.85*
3.8%	3.9%	3.7%		*estimates*		Avg Ann'l Div'd Yield	*4.6%*
315%	327%	336%	*350%*	*375%*	*375%*	Fixed Charge Coverage	*400%*



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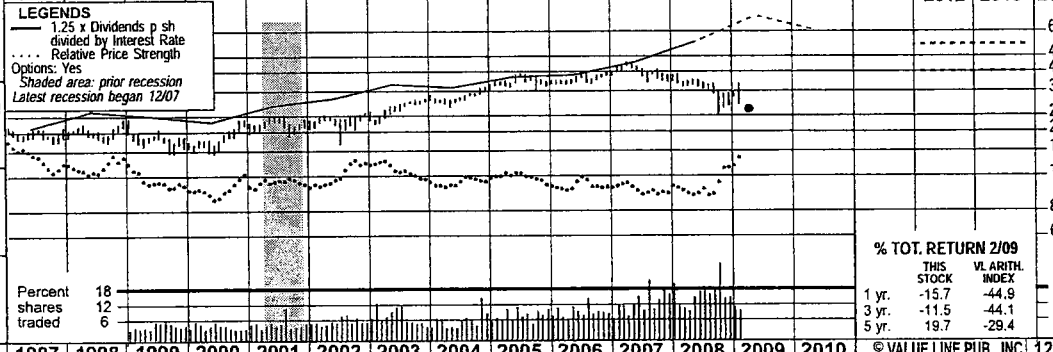
AGL RESOURCES NYSE-AGL

RECENT PRICE 25.92 | P/E RATIO 9.2 (Trailing: 9.2 Median: 14.0) | RELATIVE P/E RATIO 0.89 | DIV'D YLD 6.7% | VALUE LINE

TIMELINESS 2 Raised 2/13/09
SAFETY 2 New 7/27/90
TECHNICAL 2 Raised 3/6/09
BETA .75 (1.00 = Market)

High:	23.4	23.4	23.2	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1	34.9
Low:	17.7	15.6	15.5	19.0	17.3	21.9	26.5	32.0	34.4	35.2	24.0	25.8

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+110%)	24%
Low	40	(+55%)	16%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	3	0	0	1	0	0	2	1
to Sell	0	2	0	0	1	0	0	3	1

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	105	131	92
to Sell	127	106	130
Hld's(000)	47696	46762	48796

Percent shares traded 18 12 6

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-15.7	-44.9
3 yr.	-11.5	-44.1
5 yr.	19.7	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
22.73	23.59	19.32	21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	*35.90*	*36.40*	Revenues per sh A	*39.40*
2.25	2.24	2.33	2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	*4.70*	*4.85*	"Cash Flow" per sh	*5.30*
1.08	1.17	1.33	1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	*2.70*	*2.85*	Earnings per sh A B	*3.20*
1.04	1.04	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	*1.72*	*1.76*	Div'ds Decl'd per sh C■	*1.88*
2.49	2.37	2.17	2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	*4.35*	*4.30*	Cap'l Spending per sh	*5.00*
9.90	10.19	10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	*21.55*	*21.85*	Book Value per sh D	*21.75*
49.72	50.86	55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	*78.00*	*79.00*	Common Shs Outst'g E	*85.00*
17.9	15.1	12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.76	*Value Line*		Relative P/E Ratio	*1.00*
5.4%	5.9%	6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $2541.0 mill. Due in 5 Yrs $1410 mill.
LT Debt $1675.0 mill. LT Interest $80.0 mill.
(Total interest coverage: 4.0x)

Leases, Uncapitalized Annual rentals $30.0 mill.
Pension Assets-12/08 $242.0 mill. Oblig. $442.0 mill.

Pfd Stock None

Common Stock 76,902,777 shs.
as of 1/30/09
MARKET CAP: $2.0 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
1068.6	607.4	1049.3	868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	*2800*	*2875*	Revenues ($mill) A	*3350*
52.1	71.1	82.3	103.0	132.4	153.0	193.0	212.0	211.0	207.6	*210*	*225*	Net Profit ($mill)	*270*
33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	38.9%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	*7.5%*	*7.8%*	Net Profit Margin	*8.1%*
45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	*50.0%*	*46.5%*	Long-Term Debt Ratio	*45.0%*
49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	*50.0%*	*53.5%*	Common Equity Ratio	*55.0%*
1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	*3355*	*3225*	Total Capital ($mill)	*3350*
1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	*3950*	*4100*	Net Plant ($mill)	*4400*
5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	*7.5%*	*7.5%*	*8.0%*	Return on Total Cap'l	*9.0%*
7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	*12.5%*	*13.0%*	Return on Shr. Equity	*14.5%*
7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	*12.5%*	*13.0%*	Return on Com Equity	*14.5%*
NMF	3.2%	4.2%	7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	*5.0%*	*4.5%*	*5.0%*	Retained to Com Eq	*6.0%*
101%	72%	65%	52%	53%	49%	52%	52%	58%	60%	*64%*	*62%*	All Div'ds to Net Prof	*59%*

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	20.0	21.0	16.0
Other	1802.0	1790.0	2026.0
Current Assets	1822.0	1811.0	2042.0
Accts Payable	213.0	172.0	202.0
Debt Due	539.0	580.0	866.0
Other	875.0	893.0	915.0
Current Liab.	1627.0	1645.0	1983.0
Fix. Chg. Cov.	397%	391%	416%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	4.5%	17.5%	2.5%
"Cash Flow"	6.5%	7.0%	2.5%
Earnings	7.0%	11.5%	3.0%
Dividends	3.5%	6.5%	2.5%
Book Value	7.0%	11.5%	.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1044	436	434	707	2621
2007	973	467	369	685	2494
2008	1012	444	539	805	2800
2009	*1030*	*490*	*505*	*775*	*2800*
2010	*1045*	*505*	*520*	*805*	*2875*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.41	.25	.46	.60	2.72
2007	1.29	.40	.17	.86	2.72
2008	1.16	.30	.28	.97	2.71
2009	*1.20*	*.35*	*.30*	*.85*	*2.70*
2010	*1.25*	*.35*	*.35*	*.90*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.31	.31	.31	.37	1.30
2006	.37	.37	.37	.37	1.48
2007	.41	.41	.41	.41	1.64
2008	.42	.42	.42	.42	1.68
2009	.43				

BUSINESS: AGL Resources, Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, and Virginia Natural Gas. The utilities have more than 2.2 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Maryland. Engaged in nonregulated natural gas marketing and other allied services. Also wholesales and retails propane. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. Officers/directors own less than 1.0% of common (3/08 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

Shares of AGL Resources have held up better than the broader market over the past six months. That's owing to the steadiness of its underlying operations. Share net roughly equaled the tally reached in the prior two years. In 2008, healthy performances at the Wholesale Services and Energy Investments units were roughly offset by lower operating earnings at the Distribution and Retail Energy businesses. (Note: AGL is the stock's new ticker symbol).

The economic environment should remain challenging in the current year. Slower customer growth ought to hinder results at the company's utility operations. Moreover, we expect higher development and maintenance costs and a return to a more normal earnings level at the Wholesale Services business. Overall, AGL anticipates share net of $2.65-$2.75 for 2009, assuming normal weather patterns. Our estimate lies at the midpoint of this range. Bottom-line growth may well resume in 2010, assuming success at obtaining rate relief (discussed below).

The company is seeking higher rates. It will have four rate cases in the next two years, beginning with a filing in New Jersey. AGL's focus on procuring rate relief is encouraging, as the company depends upon such approved revenue increases to cope with higher costs and compensate it for investments made in its utility operations. Still, what pressures the rate boards may face remain unclear.

The board of directors has recently approved a modest dividend increase. Starting with the March payout, the quarterly dividend will now be $0.43. A modest increase makes sense, given stalled earnings growth and a lower cash balance in recent times. Slow, but steady, dividend growth will likely continue at AGL in the coming years.

This issue has good appeal at present. The shares have improved a notch in Timeliness since our December review, and are now ranked 2 (Above Average). Moreover, AGL earns high marks for Safety, Price Stability, and Earnings Predictability. In addition, the stock's healthy dividend yield should appeal to income investors. Overall, this equity offers attractive total return potential for a utility.

Michael Napoli, CPA *March 13, 2009*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, ($0.83); '99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late April. (C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2008: $418 million, $5.44/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

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ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
20.24	9.6 (Trailing: 10.0 Median: 16.0)	0.93	6.6%

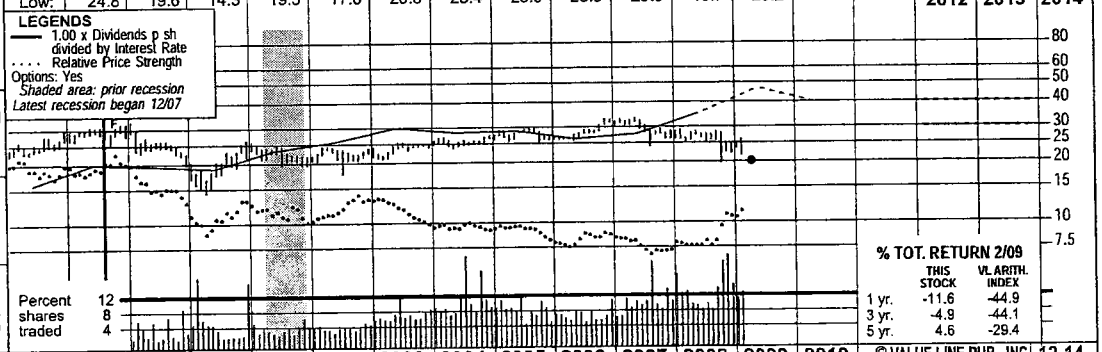
VALUE LINE

TIMELINESS 2 Raised 12/12/08
SAFETY 2 Raised 12/16/05
TECHNICAL 2 Raised 3/13/09
BETA .60 (1.00 = Market)

High:	32.3	33.0	26.3	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3	26.2
Low:	24.8	19.6	14.3	19.5	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.2

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+100%)	23%
Low	30	(+50%)	15%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	3	0	1	1	0	1	1

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	112	119	103
to Sell	103	89	119
Hld's(000)	58504	58318	56301

Percent shares traded 12 8 4

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-11.6	-44.9
3 yr.	-4.9	-44.1
5 yr.	4.6	-29.4

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
22.09	26.61	35.36	22.82	54.39	46.50	61.75	75.27	66.03	79.52	82.60	84.95	Revenues per sh A	94.55
2.62	3.01	3.03	3.39	3.23	2.91	3.90	4.26	4.14	4.19	4.35	4.40	"Cash Flow" per sh	4.80
.81	1.03	1.47	1.45	1.71	1.58	1.72	2.00	1.94	2.00	2.10	2.15	Earnings per sh A B	2.50
1.10	1.14	1.16	1.18	1.20	1.22	1.24	1.26	1.28	1.30	1.32	1.34	Div'ds Decl'd per sh C■	1.40
3.53	2.36	2.77	3.17	3.10	3.03	4.14	5.20	4.39	5.20	5.50	5.75	Cap'l Spending per sh	6.60
12.09	12.28	14.31	13.75	16.66	18.05	19.90	20.16	22.01	22.60	24.05	24.70	Book Value per sh	26.90
31.25	31.95	40.79	41.68	51.48	62.80	80.54	81.74	89.33	90.81	92.00	93.00	Common Shs Outst'g D	110.00
33.0	18.9	15.6	15.2	13.4	15.9	16.1	13.5	15.9	13.6	Bold figures are		Avg Ann'l P/E Ratio	14.0
1.88	1.23	.80	.83	.76	.84	.86	.73	.84	.84	Value Line		Relative P/E Ratio	.95
4.1%	5.9%	5.1%	5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	estimates		Avg Ann'l Div'd Yield	4.0%
690.2	850.2	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	7600	7900	Revenues ($mill) A	10400
25.0	32.2	56.1	59.7	79.5	86.2	135.8	162.3	170.5	180.3	195	200	Net Profit ($mill)	275
35.0%	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	39.0%	39.0%	Income Tax Rate	40.5%
3.6%	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	2.6%	2.5%	Net Profit Margin	2.6%
50.0%	48.1%	54.3%	53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	48.5%	48.0%	Long-Term Debt Ratio	49.0%
50.0%	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	51.5%	52.0%	Common Equity Ratio	51.0%
755.1	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	4300	4415	Total Capital ($mill)	5800
965.8	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	4350	4560	Net Plant ($mill)	5850
5.1%	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	6.0%	6.0%	Return on Total Cap'l	6.0%
6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	9.0%	8.5%	Return on Shr. Equity	9.5%
6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	9.0%	8.5%	Return on Com Equity	9.5%
NMF	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	3.5%	3.5%	Retained to Com Eq	4.0%
NMF	112%	79%	82%	70%	77%	73%	63%	65%	65%	62%	62%	All Div'ds to Net Prof	56%

CAPITAL STRUCTURE as of 12/31/08
Total Debt $2481.2 mill. **Due in 5 Yrs** $1360.0 mill.
LT Debt $1719.9 mill. **LT Interest** $105.0 mill.
(LT interest earned: 2.9x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $18.4 mill.
Pfd Stock None
Pension Assets-9/08 $341.4 mill. Oblig. $337.6 mill.
Common Stock 91,634,602 shs. as of 1/27/09
MARKET CAP: $1.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	12/31/08
Cash Assets	60.7	46.7	69.8
Other	1008.2	1238.4	1613.3
Current Assets	1068.9	1285.1	1683.1
Accts Payable	355.3	395.4	815.1
Debt Due	154.4	351.3	761.3
Other	410.0	460.4	441.5
Current Liab.	919.7	1207.1	2017.9
Fix. Chg. Cov.	405%	450%	430%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	9.5%	14.5%	4.0%
"Cash Flow"	3.5%	5.5%	2.5%
Earnings	2.5%	5.0%	4.0%
Dividends	2.5%	1.5%	1.5%
Book Value	6.5%	7.5%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	2283.8	2033.8	863.2	971.6	6152.4
2007	1602.6	2075.6	1218.2	1002.0	5898.4
2008	1657.5	2484.0	1639.1	1440.7	7221.3
2009	1716.3	2585	1750	1548.7	7600
2010	1830	2900	1710	1460	7900

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.88	1.10	d.22	.25	2.00
2007	.97	1.20	d.15	d.05	1.94
2008	.82	1.24	d.07	.02	2.00
2009	.83	1.33	d.05	d.01	2.10
2010	.90	1.35	d.06	d.04	2.15

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.31	.31	.31	.315	1.25
2006	.315	.315	.315	.32	1.27
2007	.32	.32	.32	.325	1.29
2008	.325	.325	.325	.33	1.31
2009	.33				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to 3.2 million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2008 gas volumes: 293 MMcf. Breakdown: 56%, residential; 32%, commercial; 7%, industrial; and 5% other. 2008 depreciation rate 3.5%. Has around 4,560 employees. Officers and directors own approximately 1.9% of common stock (12/08 Proxy). Chairman and Chief Executive Officer: Robert W. Best. Incorporated: Texas. Address: P.O. Box 650205, Dallas, Texas 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy's core natural gas utility has performed nicely thus far in fiscal 2009 (which ends on September 30th). That can be attributed partially to an increase in rates, primarily for the Mid-Tex and Louisiana divisions. What's more, there has been a steady rise in throughput. And it's worth noting that bad debt expense as a percentage of revenues has been lower, reflecting more aggressive collection efforts.

Results for the other operations have been a mixed bag. The pipeline and storage segment is enjoying expanded transportation margins earned under asset optimization agreements. But the performance of the regulated transmission and storage segment is being weighed down by a rise in employee and pipeline maintenance costs. Also, the nonregulated marketing segment is encountering a reduction in unrealized margins, reflecting less volatility in natural gas prices.

All things considered, earnings per share stand to rise around 5%, to $2.10, this fiscal year. Assuming further expansion in operating margins, the bottom line may advance to $2.15 a share in fiscal 2010.

We envision steady, though unexciting, profit growth over the 2012-2014 period. The utility is one of the country's leading natural gas-only distributors, now serving customers across 12 states. Moreover, the unregulated segments, especially pipelines, possess healthy overall prospects. Lastly, management may get back to its successful strategy of purchasing less-efficient utilities and shoring up their profitability via expense-reduction efforts, rate relief, and aggressive marketing. In the present configuration, annual share-net gains may be in the mid-single-digit range over the 3- to 5-year time frame.

The good-quality stock offers an appealing dividend yield. Further moderate hikes in the payout seem plausible, as well. Earnings coverage ought to remain adequate. The shares are timely.

For a natural gas utility stock, total return possibilities appear decent. Meter growth has slowed, but the company is benefiting from a high level of gas flowing through its Texas pipelines from the Barnett Shale.

Frederick L. Harris, III *March 13, 2009*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '99, d23¢; '00, 12¢; '03, d17¢; '06, d18¢; '07, d2¢. Next egs. rpt. due early May. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	80

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LACLEDE GROUP NYSE-LG

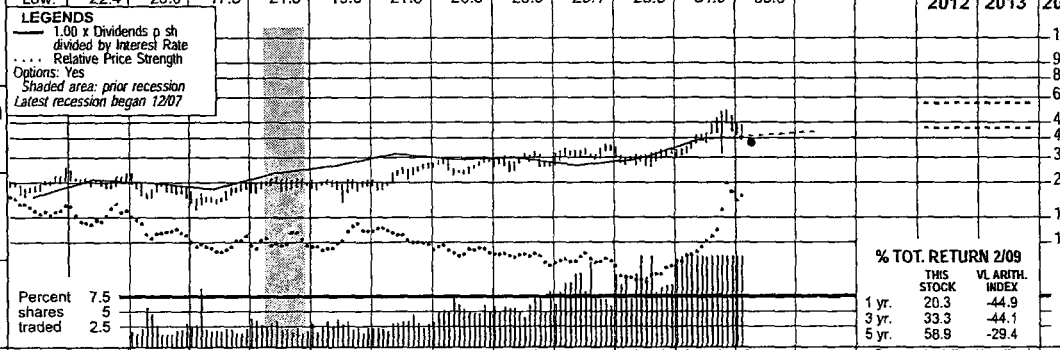
RECENT PRICE 38.10 | P/E RATIO 13.4 (Trailing: 12.4 Median: 15.0) | RELATIVE P/E RATIO 1.30 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 2 Raised 10/10/08
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Lowered 2/13/09
BETA .65 (1.00 = Market)

High:	27.9	27.0	24.8	25.5	25.0	30.0	32.5	34.3	37.5	36.0	55.8	48.3
Low:	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9	29.1	28.8	31.9	38.0

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+55%)	15%
Low	45	(+20%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	9	0	0	2	0	0	6	0
to Sell	0	9	0	0	2	0	0	6	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	72	97	82
to Sell	55	50	72
Hld's(000)	10492	11750	11943

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	20.3	-44.9
3 yr.	33.3	-44.1
5 yr.	58.9	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
32.33	33.43	24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	102.65	96.10	Revenues per sh	111.55
2.81	2.65	2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	4.65	4.50	"Cash Flow" per sh	5.40
1.61	1.42	1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	2.85	2.60	Earnings per sh A B	3.00
1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	1.53	1.57	Div'ds Decl'd per sh C■	1.70
2.62	2.50	2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	2.65	2.70	Cap'l Spending per sh	3.45
12.19	12.44	13.05	13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	23.60	25.10	Book Value per sh D	28.05
15.59	15.67	17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	22.50	23.00	Common Shs Outst'g E	26.00
13.5	16.4	15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	Bold figures are		Avg Ann'l P/E Ratio	17.5
.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	.89	Value Line		Relative P/E Ratio	1.15
5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	estimates		Avg Ann'l Div'd Yield	3.2%

CAPITAL STRUCTURE as of 12/31/08
Total Debt $652.9 mill. Due in 5 Yrs $50.0 mill.
LT Debt $389.2 mill. LT Interest $25.0 mill.
(Total interest coverage: 3.0x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/08 $248.3 mill. Oblig. $308.7 mill.
Pfd Stock $.5 mill. Pfd Div'd $.03 mill.
Common Stock 22,135,185 shs. as of 1/29/09

MARKET CAP: $850 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
491.6	566.1	1002.1	755.2	1050.3	1250.3	1597.0	1997.6	2021.6	2209.0	2310	2210	Revenues ($mill) A	2900
26.9	26.0	30.5	22.4	34.6	36.1	40.1	50.5	49.8	57.6	65.0	60.0	Net Profit ($mill)	80.0
35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	31.3%	31.5%	31.5%	Income Tax Rate	35.0%
5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	2.6%	2.8%	2.7%	Net Profit Margin	2.8%
41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	48.1%	49.5%	45.3%	44.4%	45.0%	45.0%	Long-Term Debt Ratio	47.0%
57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	55.5%	55.0%	55.0%	Common Equity Ratio	53.0%
488.6	519.2	574.1	546.6	605.0	737.4	707.9	798.9	784.5	876.1	965	1050	Total Capital ($mill)	1375
519.4	575.4	602.5	594.4	621.2	646.9	679.5	763.8	793.8	823.2	855	880	Net Plant ($mill)	980
7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	8.1%	8.0%	7.0%	Return on Total Cap'l	7.0%
9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	11.8%	12.5%	10.5%	Return on Shr. Equity	11.0%
9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	12.5%	10.5%	Return on Com Equity	11.0%
1.0%	.2%	1.8%	NMF	3.1%	2.7%	3.1%	5.1%	4.3%	5.2%	6.0%	4.0%	Retained to Com Eq	5.0%
89%	98%	83%	113%	74%	73%	72%	59%	63%	56%	53%	60%	All Div'ds to Net Prof	55%

CURRENT POSITION ($MILL.)	2007	2008	12/31/08
Cash Assets	52.7	14.9	30.1
Other	414.6	547.0	609.8
Current Assets	467.3	561.9	639.9
Accts Payable	106.8	159.6	175.3
Debt Due	251.6	216.1	263.7
Other	115.3	103.5	121.7
Current Liab.	473.7	479.2	560.7
Fix. Chg. Cov.	282%	377%	330%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	11.5%	14.0%	2.5%
"Cash Flow"	2.0%	6.5%	5.5%
Earnings	3.5%	9.5%	3.5%
Dividends	1.0%	1.5%	2.5%
Book Value	3.5%	5.5%	5.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	689.2	708.8	330.6	269.0	1997.6
2007	539.6	700.8	457.9	323.3	2021.6
2008	504.0	747.7	505.5	451.8	2209.0
2009	674.3	700	485	450.7	2310
2010	555	555	550	550	2210

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	1.23	1.05	.13	d.04	2.37
2007	.89	.97	.43	.03	2.31
2008	.99	1.39	.41	d.14	2.64
2009	1.42	1.25	.30	d.12	2.85
2010	1.03	1.21	.38	d.02	2.60

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.34	.345	.345	.345	1.38
2006	.345	.355	.355	.355	1.41
2007	.365	.365	.365	.365	1.46
2008	.375	.375	.375	.375	1.50
2009	.385				

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 10 other counties. Has roughly 630,000 customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Therms sold and transported in fiscal 2008: 1.08 mill. Revenue mix for regulated operations: residential, 62%; commercial and industrial, 24%; transportation, 1%; other, 13%. Has around 1,807 employees. Officers and directors own approximately 7.2% of common shares (1/09 proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Laclede Group started fiscal 2009 (which ends on September 30th) in excellent fashion. That was made possible primarily by Laclede Energy Resources, which benefited, in part, from higher volumes (attributable to contracting for additional pipeline capacity). That division also enjoyed wider margins on sales of natural gas, due to depressed supply pricing in the Midwest from increased shale supply production. Meanwhile, profits for Laclede Gas were moderately higher than the year-earlier figure, arising from greater income from natural gas sales, brought about by colder weather and higher Infrastructure System Replacement Surcharge revenues. But a rise in both operating expenses and investment losses largely offset these results.

At this juncture, the bottom line stands to advance about 8%, to $2.85 a share, in fiscal 2009. Earnings may be lower next year, however, because of the tough comparison.

Unexciting results appear to be in store for the energy firm over the 2012-2014 period. Growth in the customer base for the natural gas distribution unit will probably remain moderate. (In fact, the number of customers in fiscal 2008 was just 2% higher than in fiscal 1998.) That's because the service territory, located in eastern Missouri, is in a mature phase. We think the non-regulated division has promising expansion opportunities, but it has contributed only a small portion to Laclede Group's profits on a historical basis. A major acquisition could help to offset this, but it seems that no such plans are on the agenda at this time. Consequently, annual earnings-per-share growth could be just between 4% and 5% over the 3- to 5-year horizon.

This stock, ranked favorably for both Timeliness and Safety, offers a modestly appealing current yield. Additional hikes in the dividend will likely be gradual, though. That is largely because of the regulated gas operation's unspectacular long-term prospects.

The shares of Laclede have limited long-term total-return potential, given the current quotation and our assumption of moderate future increases in the distribution.

Frederick L. Harris, III *March 13, 2009*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late April. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '08: $340.4 mill., $15.48/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	75

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NEW JERSEY RES. NYSE-NJR

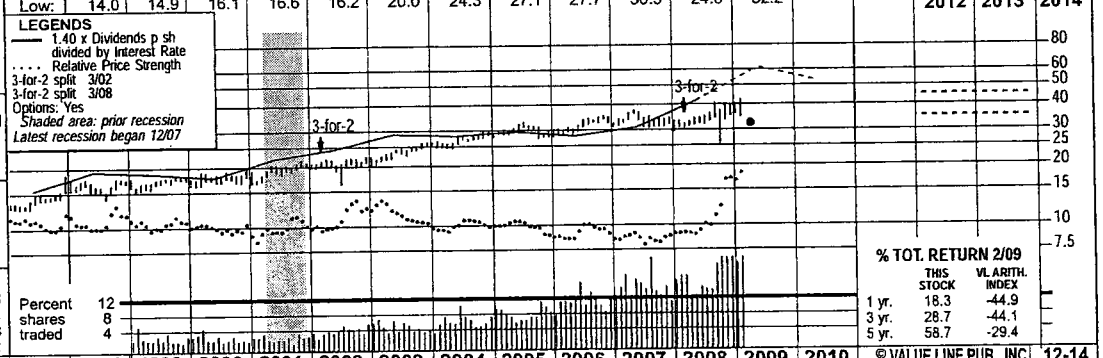
RECENT PRICE 32.25 | P/E RATIO 12.9 (Trailing: 11.7 / Median: 15.0) | RELATIVE P/E RATIO 1.25 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 2 Raised 11/28/08
SAFETY 1 Raised 9/15/06
TECHNICAL 2 Raised 11/21/08
BETA .65 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	17.9	18.3	19.8	21.7	22.4	26.4	29.7	32.9	35.4	37.6	41.1	42.4
Low:	14.0	14.9	16.1	16.6	16.2	20.0	24.3	27.1	27.7	30.3	24.6	32.2

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/02
3-for-2 split 3/08
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+40%)	12%
Low	35	(+10%)	6%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	1	2	0	0	1	0	1	2	3
to Sell	0	2	0	0	1	0	0	1	4

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	85	90	64
to Sell	70	62	88
Hld's(000)	26518	26910	26312

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	18.3	-44.9
3 yr.	28.7	-44.1
5 yr.	58.7	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
12.02	12.81	11.36	13.48	17.31	17.73	22.65	29.42	51.22	44.11	62.29	60.89	76.19	79.63	72.62	90.74	*89.20*	*90.95*	Revenues per sh A	*95.00*
1.42	1.54	1.42	1.48	1.63	1.74	1.86	1.99	2.12	2.14	2.38	2.50	2.62	2.73	2.44	3.62	*3.40*	*3.60*	"Cash Flow" per sh	*3.75*
.76	.84	.86	.92	.99	1.04	1.11	1.20	1.30	1.39	1.59	1.70	1.77	1.87	1.55	2.70	*2.50*	*2.70*	Earnings per sh B	*2.85*
.68	.68	.68	.69	.71	.73	.75	.76	.78	.80	.83	.87	.91	.96	1.01	1.11	*1.24*	*1.28*	Div'ds Decl'd per sh C■	*1.40*
1.54	1.40	1.18	1.19	1.15	1.07	1.21	1.23	1.10	1.02	1.14	1.45	1.28	1.28	1.46	1.72	*1.75*	*1.75*	Cap'l Spending per sh	*1.80*
6.54	6.43	6.47	6.73	6.92	7.26	7.57	8.29	8.80	8.71	10.26	11.25	10.60	15.00	15.50	17.28	*18.80*	*20.75*	Book Value per sh D	*25.75*
37.84	38.93	40.03	40.69	40.23	40.07	39.92	39.59	40.00	41.50	40.85	41.61	41.32	41.44	41.61	42.06	*42.50*	*43.00*	Common Shs Outst'g E	*45.00*
15.1	13.0	11.8	13.6	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.89	.85	.79	.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.87	1.15	.77	*Value Line*		Relative P/E Ratio	*.95*
5.8%	6.2%	6.7%	5.6%	5.3%	4.6%	4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $757.1 mill. Due in 5 Yrs $175.6 mill.
LT Debt $460.7 mill. LT Interest $16.9 mill.
Incl. $8.8 mill. capitalized leases.
(LT interest earned: 4.8x; total interest coverage: 4.8x)
Pension Assets-9/08 $80.6 mill. Oblig. $102.4 mill.

Pfd Stock None

Common Stock 42,318,558 shs. as of 2/4/09
MARKET CAP: $1.4 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
904.3	1164.5	2048.4	1830.8	2544.4	2533.6	3148.3	3299.6	3021.8	3816.2	*3790*	*3910*	Revenues ($mill) A	*4275*
44.9	47.9	52.3	56.8	65.4	71.6	74.4	78.5	65.3	113.9	*105*	*115*	Net Profit ($mill)	*130*
36.2%	37.8%	38.0%	38.7%	39.4%	39.1%	39.1%	38.9%	38.8%	37.8%	*39.0%*	*39.0%*	Income Tax Rate	*40.0%*
5.0%	4.1%	2.6%	3.1%	2.6%	2.8%	2.4%	2.4%	2.2%	3.0%	*2.8%*	*3.0%*	Net Profit Margin	*3.0%*
48.7%	47.0%	50.1%	50.6%	38.1%	40.3%	42.0%	34.8%	37.3%	38.5%	*38.5%*	*37.0%*	Long-Term Debt Ratio	*33.0%*
51.2%	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	62.7%	61.5%	*61.5%*	*63.0%*	Common Equity Ratio	*67.0%*
590.4	620.1	706.2	732.4	676.8	783.8	755.3	954.0	1028.0	1182.1	*1300*	*1415*	Total Capital ($mill)	*1730*
705.4	730.6	743.9	756.4	852.6	880.4	905.1	934.9	970.9	1017.3	*1040*	*1060*	Net Plant ($mill)	*1125*
9.0%	9.0%	8.5%	8.7%	10.7%	10.1%	11.2%	9.6%	7.7%	10.7%	*9.0%*	*9.0%*	Return on Total Cap'l	*8.0%*
14.8%	14.6%	14.8%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	*13.5%*	*13.0%*	Return on Shr. Equity	*11.0%*
14.8%	14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	*13.5%*	*13.0%*	Return on Com Equity	*11.0%*
5.0%	5.4%	6.1%	6.9%	7.7%	7.8%	8.5%	6.3%	3.6%	9.5%	*6.5%*	*7.0%*	Retained to Com Eq	*5.5%*
67%	63%	59%	56%	51%	49%	50%	50%	64%	40%	*50%*	*47%*	All Div'ds to Net Prof	*49%*

CURRENT POSITION ($MILL.)	2007	2008	12/31/08
Cash Assets	5.1	42.6	26.0
Other	794.8	1067.1	1046.5
Current Assets	799.9	1109.7	1072.5
Accts Payable	64.4	61.7	43.4
Debt Due	260.8	238.3	296.4
Other	378.1	594.0	578.7
Current Liab.	703.3	894.0	918.5
Fix. Chg. Cov.	461%	450%	450%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	17.5%	9.0%	2.5%
"Cash Flow"	6.0%	6.0%	4.0%
Earnings	7.5%	7.5%	5.5%
Dividends	4.0%	5.0%	5.5%
Book Value	8.5%	11.5%	8.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	1164	1064	536.1	535.5	3299.6
2007	737.4	1029	662.2	593.2	3021.8
2008	811.1	1178	1000	827.1	3816.2
2009	801.3	*1175*	*993.7*	*820*	*3790*
2010	*830*	*1205*	*1025*	*850*	*3910*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.82	1.43	d.09	d.29	1.87
2007	.70	.19	.60	.06	1.55 F
2008	.87	.30	d.18	1.86	2.70
2009	.77	*.33*	*d.10*	*1.50*	*2.50*
2010	*.80*	*.40*	*d.05*	*1.55*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C E■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.227	.227	.227	.227	.91
2006	.24	.24	.24	.24	.96
2007	.253	.253	.253	.253	1.01
2008	.267	.28	.28	.28	1.11
2009	.31				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 484,000 customers at 9/30/08 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2008 volume: 99.6 bill. cu. ft. (59% firm, 6% interruptible industrial and electric utility, 35% off-system and capacity release). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2008 dep. rate: 2.9%. Has 854 empls. Off./dir. own about 1.7% of common (12/08Proxy). Chrmn., CEO, & Pres. : Laurence M. Downes. Inc.: N.J. Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

New Jersey Resources did not perform as well as expected during its 2009 fiscal first quarter (ended December 31st). The New Jersey Natural Gas (NJNG) unit did benefit from a recent rate case increase, and steady customer growth. That division added roughly 1,765 new customers over the December interim. However, that was not sufficient enough to offset the downturn at the company's NJR Energy Services (NJRES) unit. Narrower winter storage spreads, and a slowdown in contracted transportation capacity across the Northeast, cut this segment's contribution to earnings in half. Consequently, NJR's bottom line suffered.

Thus, we have trimmed this year's earnings figure approximately 11%. The domestic recession has prompted many consumers in NJR's service areas to scale back spending. Meanwhile, home foreclosure resulting in vacant domiciles adds another element of risk and uncertainty. In all, 2009's prospects have been hindered. But, on a brighter note,

Economic stimulus programs may bear fruit down the road. NJNG recently filed a proposal with the New Jersey Board of Public Utilities for two programs aimed at stimulating the local economy through energy efficiency, job creation, and infrastructure spending. If approved, these capital projects would create up to 100 jobs. The benefit to NJR would be an increase in the safety and reliability of its distribution system.

Meantime, we have introduced a 2010 bottom-line estimate of $2.70 a share. Top-line volumes ought to rebound next year due to the addition of utility customers, coupled with NJRES' capital projects. The Steckman Ridge storage facility and the recently completed 16-inch main pipeline both ought to contribute nicely.

These timely shares may appeal to momentum- and income-oriented accounts (Timeliness: 2). And the recent dividend hike of 10.7% only sweetens the deal; dividend growth is a hallmark here. Finally, New Jersey Resources' ability to hold up in such a difficult market is a plus. This characteristic is supported by the stock's top Safety rank (1), and high marks for Financial Strength and Price Stability.

Bryan Fong *March 13, 2009*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late April.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2008: $340.7 million, $8.09/share.
(E) In millions, adjusted for split.
(F) Restated.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	50

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NICOR, INC. NYSE-GAS

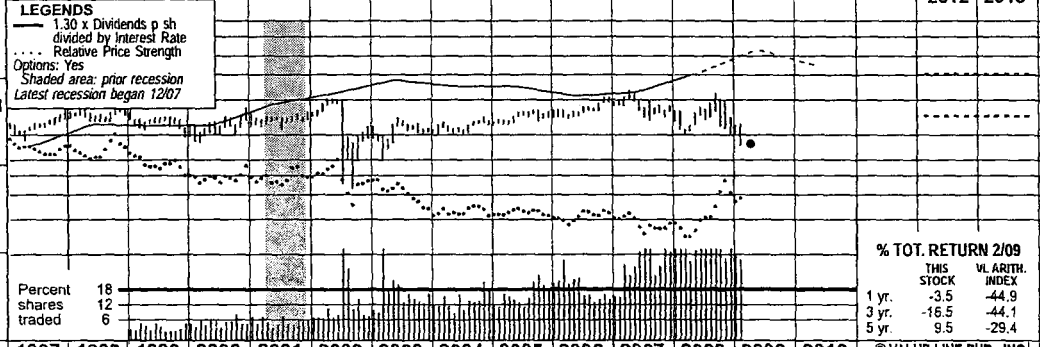
RECENT PRICE 29.17 | P/E RATIO 11.4 (Trailing: 11.1 Median: 15.0) | RELATIVE P/E RATIO 1.11 | DIV'D YLD 6.4% | VALUE LINE

TIMELINESS 3 Raised 12/7/07
SAFETY 3 Lowered 6/17/05
TECHNICAL 3 Lowered 2/20/09
BETA .75 (1.00 = Market)

High:	44.4	42.9	43.9	42.4	49.0	39.3	39.7	43.0	49.9	53.7	52.0	36.3
Low:	37.1	31.2	29.4	34.0	17.3	23.7	32.0	35.5	38.7	37.8	32.3	28.4

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+125%)	26%
Low	40	(+35%)	13%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	0	0	0	0	0	1	0	0	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	91	119	105
to Sell	120	90	125
Hld's(000)	31875	32273	32539

Percent shares traded 18 12 6

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-3.5	-44.9
3 yr.	-16.5	-44.1
5 yr.	9.5	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
31.02	31.23	29.42	37.39	41.33	30.84	34.45	50.52	57.30	43.11	60.46	62.12	76.00	65.92	69.20	83.68	*78.90*	*82.20*	Revenues per sh	*98.35*
3.80	4.11	4.19	4.97	5.29	5.21	5.59	6.16	6.41	6.03	5.37	6.00	6.19	6.82	6.96	6.85	*6.50*	*7.00*	"Cash Flow" per sh	*7.95*
1.97	2.07	1.96	2.42	2.55	2.31	2.57	2.94	3.01	2.88	2.11	2.22	2.27	2.87	2.99	2.63	*2.50*	*2.90*	Earnings per sh A	*3.30*
1.22	1.25	1.28	1.32	1.40	1.48	1.54	1.66	1.76	1.84	1.86	1.86	1.86	1.86	1.86	1.86	*1.86*	*1.86*	Div'ds Decl'd per sh B■	*1.86*
2.62	3.34	3.12	2.42	2.34	2.87	3.28	3.48	4.18	4.37	4.12	4.32	4.57	4.17	3.77	5.54	*4.35*	*4.50*	Cap'l Spending per sh	*4.85*
13.05	13.26	13.67	14.74	15.43	15.97	16.80	15.56	16.39	16.55	17.13	16.99	18.36	19.43	20.58	21.55	*22.25*	*23.30*	Book Value per sh	*27.05*
53.96	51.54	50.30	49.49	48.22	47.51	46.89	45.49	44.40	44.01	44.04	44.10	44.18	44.90	45.90	45.13	*45.00*	*45.00*	Common Shs Outst'g C	*45.00*
14.1	12.5	13.1	12.5	14.2	17.6	14.6	11.9	12.8	13.1	15.8	15.9	17.3	15.0	15.0	15.1	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.83	.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.84	.92	.81	.80	.93	*Value Line*		Relative P/E Ratio	*1.05*
4.4%	4.8%	5.0%	4.4%	3.9%	3.6%	4.1%	4.7%	4.6%	4.9%	5.6%	5.3%	4.7%	4.3%	4.2%	4.7%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $1237.9 mill. Due in 5 Yrs $914.9 mill.
LT Debt $448.0 mill. LT Interest $5.0 mill.
(Total interest coverage: 5.1x)

Pension Assets-12/08 $306.6 mill. Oblig. $270.2 mill.

Pfd Stock $.6 mill. Pfd Div'd None

Common Stock 45,198,311 shares as of 2/17/09
MARKET CAP: $1.3 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	3357.8	2960.0	3176.3	3776.6	*3550*	*3700*	Revenues ($mill)	*4200*
121.9	136.4	136.3	128.0	93.1	98.1	101.1	128.3	135.2	119.5	*112.5*	*130*	Net Profit ($mill)	*150*
34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	28.3%	26.3%	26.6%	27.0%	*27.0%*	*27.0%*	Income Tax Rate	*27.0%*
7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.0%	4.3%	4.3%	3.2%	*3.2%*	*3.5%*	Net Profit Margin	*3.6%*
35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	37.4%	36.3%	30.9%	31.5%	*31%*	*30%*	Long-Term Debt Ratio	*26%*
64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	63.7%	69.0%	68.4%	*69%*	*70%*	Common Equity Ratio	*74%*
1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1297.7	1370.7	1368.0	1421.1	*1450*	*1500*	Total Capital ($mill)	*1650*
1735.2	1729.6	1768.6	1796.8	2484.2	2549.8	2659.1	2714.1	2757.3	2858.6	*2950*	*3060*	Net Plant ($mill)	*3380*
10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.4%	10.9%	11.2%	9.7%	*9.0%*	*10.0%*	Return on Total Cap'l	*10.0%*
15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	14.7%	14.3%	12.3%	*11.0%*	*12.5%*	Return on Shr. Equity	*12.0%*
15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	14.7%	14.3%	12.3%	*11.0%*	*12.5%*	Return on Com Equity	*12.0%*
6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	2.3%	5.2%	5.4%	3.6%	*3.0%*	*4.5%*	Retained to Com Eq	*5.5%*
60%	56%	58%	63%	88%	84%	81%	65%	62%	71%	*74%*	*64%*	All Div'ds to Net Prof	*56%*

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	67.6	91.9	95.5
Other	843.1	931.9	1243.4
Current Assets	910.7	1023.8	1338.9
Accts Payable	564.5	428.2	411.3
Debt Due	350.0	444.0	789.9
Other	227.9	404.2	466.8
Current Liab.	1142.4	1276.4	1668.0
Fix. Chg. Cov.	543%	544%	461%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.0%	6.5%	5.0%
"Cash Flow"	3.0%	3.0%	2.5%
Earnings	1.5%	1.0%	2.5%
Dividends	3.0%	0.5%	Nil
Book Value	3.0%	4.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1319.4	451.3	351.1	838.2	2960.0
2007	1334.7	556.9	365.2	919.5	3176.3
2008	1595.7	699.8	440.3	1040.8	3776.6
2009	*1500*	*650*	*400*	*1000*	*3550*
2010	*1550*	*675*	*425*	*1050*	*3700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.99	.19	.39	1.30	2.87
2007	1.04	.40	.32	1.22	2.98
2008	.91	.64	.03	1.05	2.63
2009	*.90*	*.35*	*.25*	*1.00*	*2.50*
2010	*1.00*	*.45*	*.35*	*1.10*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.465	.465	.465	.465	1.86
2006	.465	.465	.465	.465	1.86
2007	.465	.465	.465	.465	1.86
2008	.465	.465	.465	.465	1.86
2009	.465	.465			

BUSINESS: *Nicor Inc. is a holding company with gas distribution as its primary business.* Serves over 2.2 million customers in northern and western Illinois. 2008 gas delivered: 498.1 Bcf, incl. 222.6 Bcf from transportation. 2008 gas sales (275.5 bcf): residential, 93%; commercial, 6%; industrial, 1%. *Principal supplying pipelines:* Natural Gas Pipeline, Horizon Pipeline, and TGPC. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested oil and gas E&P, 6/93. Has about 3,900 employees. Officers/directors own about 2.2% of common stock (3/08 proxy). Chairman and Chief Executive Officer: Russ Strobel. Incorporated: Illinois. Address: 1844 Ferry Road, Naperville, Illinois 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor struggled in the second half of 2008. Most recently, the company posted earnings of $1.05 a share in the fourth quarter, which beat our estimate but still fell short of the prior-year tally. Rising costs coupled with the weak economic environment weighed on GAS' performance. As a result, annual share net fell below 2007's mark of $2.98. Nicor continues to be pressured by higher operating costs.

The company awaits a decision for a rate case filed with the Illinois Commerce Commission (ICC). Given rising expenditures, the utility filed a case for an overall increase in rates. Nicor seeks to raise its rate base by $140.4 million to reflect a return of equity of 11.15%. The new rate would allow the company to better adjust to the current market conditions. In response, the ICC proposed a base increase of $68.8 million, which reflects a cost of equity of 10.17%. The proposal also includes two rate mechanisms focused on energy efficiency. Management is in the process of responding to this offer. After this, Nicor and the ICC will move toward a final decision, which should be announced this month. Accordingly, we recommend investors monitor this situation since it will likely have a heavy bearing on this equity's performance going forward.

We have lowered our estimates for 2009. We look for the bottom line to come in at about $2.50 a share, which is near the proposed base by the ICC. This estimate assumes normal weather and is supported by this utility's steady cash flow. However, if the rate case is approved, our estimates may prove to be conservative.

We are introducing our expectations for 2010. We look for the top and bottom lines to bounce back next year. The shipping business should begin to strengthen over this time frame. Accordingly, we estimate earnings of $2.90 a share.

This stock is ranked 3 (Average) for Timeliness. Nicor's prospects are somewhat ill-defined, given the pending rate case. Thus, we recommend most investors take a wait-and-see approach. However, income-oriented accounts should note that this issue offers an attractive dividend yield, which is above the average for a natural gas utility.

Richard Gallagher *March 13, 2009*

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢); '05, 80¢; '06, (17¢); '07 (13¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Next egs. report due early May. (B) Dividends historically paid mid February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	75

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N.W. NAT'L GAS NYSE-NWN

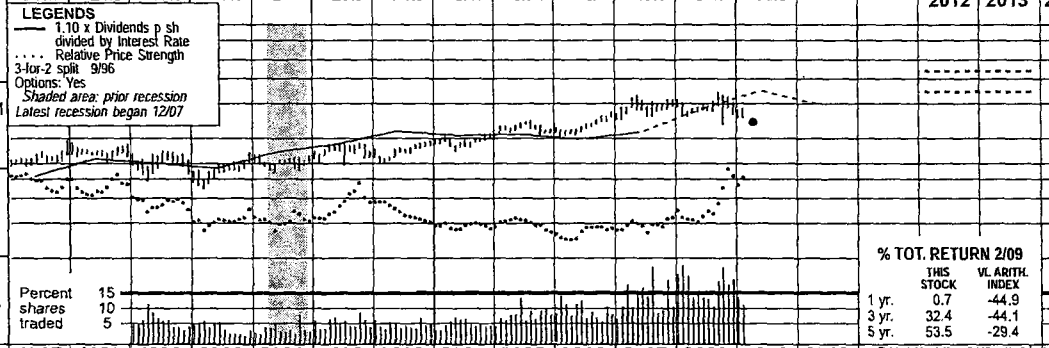
RECENT PRICE 38.95 | P/E RATIO 14.3 (Trailing: 15.1 Median: 16.0) | RELATIVE P/E RATIO 1.39 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 2 Raised 2/20/09
SAFETY 1 Raised 3/18/05
TECHNICAL 2 Raised 3/6/09
BETA .60 (1.00 = Market)

High:	30.8	27.9	27.5	26.8	30.7	31.3	34.1	39.6	43.7	52.8	55.2	45.7
Low:	24.3	19.5	17.8	21.7	23.5	24.0	27.5	32.4	32.8	39.8	37.7	38.8

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 9/96
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+80%)	19%
Low	55	(+40%)	12%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	1	0	0	0	0	0	0
Options	0	0	1	0	1	2	0	1	0
to Sell	0	0	1	0	1	2	0	2	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	77	78	65
to Sell	92	71	74
Hld's(000)	16772	16947	16310

Percent shares traded 15 10 5

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	0.7	-44.9
3 yr.	32.4	-44.1
5 yr.	53.5	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
18.15	18.30	16.02	16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.17	*39.60*	*41.50*	Revenues per sh	*48.20*
3.74	3.50	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.29	*5.60*	*5.85*	"Cash Flow" per sh	*6.75*
1.74	1.63	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.58	*2.75*	*2.85*	Earnings per sh A	*3.45*
1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	*1.58*	*1.66*	Div'ds Decl'd per sh B■	*2.00*
3.61	4.23	3.02	3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	4.15	*4.50*	*4.50*	Cap'l Spending per sh	*4.50*
13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.70	*24.90*	*26.10*	Book Value per sh	*30.50*
19.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	*26.50*	*26.50*	Common Shs Outst'g C	*28.00*
12.9	13.0	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.14	*Value Line*		Relative P/E Ratio	*1.20*
5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.2%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $760.0 mill. **Due in 5 Yrs** $259.8 mill.
LT Debt $512.0 mill. **LT Interest** $37.0 mill.

(Total interest coverage: 4.0x)

Pension Assets-12/07 $241 mill.
Oblig. $260 mill.
Pfd Stock None

Common Stock 26.5 mill. shares

MARKET CAP $1.0 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
455.8	532.1	650.3	641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	*1050*	*1100*	Revenues ($mill)	*1350*
44.9	47.8	50.2	43.8	46.0	50.6	56.1	65.2	74.5	68.5	*73.0*	*75.5*	Net Profit ($mill)	*96.5*
35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	*7.0%*	*6.9%*	Net Profit Margin	*7.2%*
46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	*47%*	*47%*	Long-Term Debt Ratio	*47%*
49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	*53%*	*53%*	Common Equity Ratio	*53%*
861.5	887.8	880.5	937.3	1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	*1180*	*1225*	Total Capital ($mill)	*1400*
895.9	934.0	965.0	995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.0	*1600*	*1660*	Net Plant ($mill)	*1900*
6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	*8.0%*	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	11.2%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.0%*
9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	11.2%	*11.0%*	*11.0%*	Return on Com Equity	*11.0%*
2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.7%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
74%	70%	67%	79%	72%	69%	63%	59%	52%	59%	*57%*	*58%*	All Div'ds to Net Prof	*58%*

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	5.8	6.1	6.9
Other	303.0	268.8	474.1
Current Assets	308.8	274.9	481.0
Accts Payable	113.6	119.7	94.4
Debt Due	129.6	148.1	248.0
Other	98.3	122.1	208.9
Current Liab.	341.5	389.9	551.3
Fx. Chg. Cov.	349%	408%	393%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '12-'14
Revenues	8.5%	8.5%	*6.5%*
"Cash Flow"	3.0%	5.5%	*5.0%*
Earnings	3.0%	6.5%	*7.0%*
Dividends	1.5%	2.0%	*5.5%*
Book Value	3.5%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	390.4	171.0	114.9	336.9	1013.2
2007	394.1	183.2	124.2	331.7	1033.2
2008	387.7	191.3	109.7	349.2	1037.9
2009	*390*	*200*	*120*	*340*	*1050*
2010	*410*	*210*	*125*	*355*	*1100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.48	.07	d.35	1.15	2.35
2007	1.77	.10	d.22	1.11	2.76
2008	1.63	.08	d.38	1.25	2.58
2009	*1.72*	*.10*	*d.34*	*1.27*	*2.75*
2010	*1.75*	*.11*	*d.33*	*1.32*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.325	.325	.325	.345	1.32
2006	.345	.345	.345	.355	1.39
2007	.355	.355	.355	.375	1.44
2008	.375	.375	.375	.395	1.52
2009	.395				

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 662,000 customers, in Oregon (90% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 55%; commercial, 28%; industrial, gas transportation, and other, 17%. Employs 1,130. Barclays Global owns 6.5% of shares; officers and directors, 1.3% (4/08 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural's fourth-quarter earnings gain was a bit above normal. In the final period of 2008, the company profited from its gas cost-sharing arrangement in Oregon, where it had lost money in the prior-year period. Operating and maintenance costs declined 12%, year to year, and the Oregon weather normalization clause helped, as well, though it had no effect on 2007 December-period profits. Despite gas cost-sharing profit in the fourth quarter, Northwest lost about $0.11 a share from the arrangement in 2008. Customer growth, though, slowed to 1.6% in 2008, well below the recent average.

Earnings will likely rise nicely in 2009. Northwest guided to a range of $2.55 to $2.70 a share this year, but we think the company will do a bit better. Even though customer growth will probably be modest in 2009, Northwest should continue to garner new accounts from customers switching to gas from other sources of heat. The revised gas cost-sharing system in Oregon should also help, as the company should benefit from gas prices that are now well below last fall; Northwest's gas cost forecast is approved by the Oregon PUC in October. The new arrangement should reduce earnings swings, as Northwest will book only 10% or 20% of the profit or loss on the cost of gas, down from one-third through 2008.

Earnings from present operations will probably rise steadily through 2012-2014. Customer growth will likely continue to exceed the U.S. average of around 1% per year. Oregon's enlightened regulations should protect Northwest from the vagaries of the weather, and Washington will probably institute a weather adjustment clause, as well. Costs should rise at a slower pace than the customer roster. But

Two large projects could significantly boost Northwest's earnings by 2014. If regulators give all necessary approvals, a gas storage project in California and a new gas pipeline in Oregon will come on stream in 2011-2012. Together, they could require over $525 million of investment by Northwest. The company would have to sell some stock, but the projects could add at least $0.35 a share to our forecast.

These top-quality shares have solid risk-adjusted total-return potential.

Sigourney B. Romaine *March 13, 2009*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03). Next earnings report due early May.

(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.

(C) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	80

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PIEDMONT NAT'L. GAS NYSE-PNY

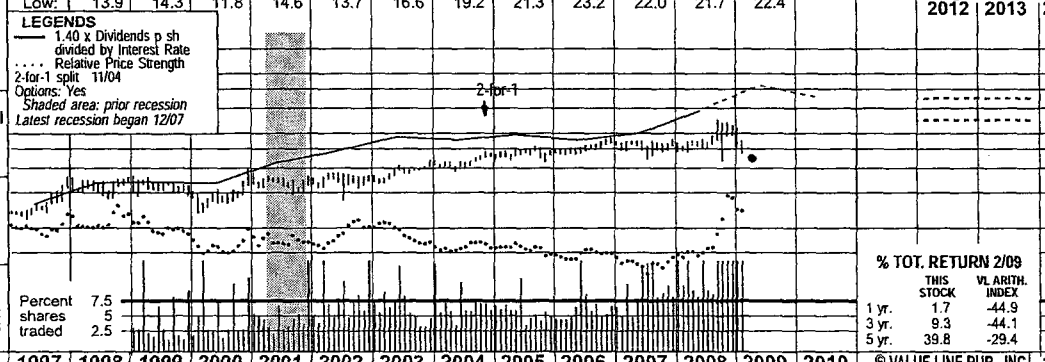
RECENT PRICE 22.46 | P/E RATIO 14.0 (Trailing: 15.0 Median: 18.0) | RELATIVE P/E RATIO 1.36 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 3 Raised 6/15/07
SAFETY 2 New 7/27/90
TECHNICAL 2 Lowered 1/9/09
BETA .65 (1.00 = Market)

High:	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0
Low:	13.9	14.3	11.8	14.6	13.7	16.6	19.2	21.3	23.2	22.0	21.7	22.4

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 11/04
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+100%)	23%
Low	35	(+55%)	16%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	78	97	82
to Sell	85	77	96
Hld's(000)	36778	36688	35228

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.7	-44.9
3 yr.	9.3	-44.1
5 yr.	39.8	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
10.57	10.82	8.76	11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	29.25	30.15	Revenues per sh A	33.15
1.14	1.13	1.25	1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	2.85	3.05	"Cash Flow" per sh	3.40
.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	1.60	1.80	Earnings per sh B	2.15
.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.05	1.10	Div'ds Decl'd per sh C■	1.25
1.58	1.95	1.72	1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	2.47	3.15	2.10	Cap'l Spending per sh	2.25
5.45	5.68	6.16	6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	12.65	13.45	Book Value per sh D	15.85
52.30	53.15	57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.26	73.50	73.50	Common Shs Outst'g E	73.00
15.4	15.7	13.8	13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	18.2	Bold figures are		Avg Ann'l P/E Ratio	18.0
.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.15	Value Line		Relative P/E Ratio	1.50
4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%	estimates		Avg Ann'l Div'd Yield	3.1%

CAPITAL STRUCTURE as of 10/31/08
Total Debt $1230.8 mill. Due in 5 Yrs $150.0 mill.
LT Debt $794.3 mill. LT Interest $55.5 mill.
(LT interest earned: 4.0x; total interest coverage: 3.7x)

Pension Assets-10/08 $150.3 mill. Oblig. $143.5 mill.

Pfd Stock None

Common Stock 73,260,672 shs. as of 12/16/08
MARKET CAP: $1.7 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
686.5	830.4	1107.9	832.0	1220.8	1529.7	1761.1	1924.6	1711.3	2089.1	2150	2215	Revenues ($mill) A	2420
58.2	64.0	65.5	62.2	74.4	95.2	101.3	97.2	104.4	110.0	120	135	Net Profit ($mill)	155
39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.4%	35.0%	35.0%	Income Tax Rate	35.0%
8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	5.5%	6.0%	Net Profit Margin	6.5%
46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	51.0%	49.5%	Long-Term Debt Ratio	47.0%
53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	49.0%	50.5%	Common Equity Ratio	53.0%
914.7	978.4	1069.4	1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	1900	1955	Total Capital ($mill)	2180
1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	2250	2300	Net Plant ($mill)	2450
8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	7.5%	8.5%	Return on Total Cap'l	8.5%
11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	12.5%	13.5%	Return on Shr. Equity	13.5%
11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	12.5%	13.5%	Return on Com Equity	13.5%
3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	4.0%	5.0%	Retained to Com Eq	6.0%
72%	71%	75%	83%	74%	66%	68%	74%	70%	69%	67%	62%	All Div'ds to Net Prof	57%

CURRENT POSITION ($MILL.)	2006	2007	10/31/08
Cash Assets	8.9	7.5	7.0
Other	467.1	427.8	593.8
Current Assets	476.0	435.3	600.8
Accts Payable	80.3	143.6	132.3
Debt Due	170.0	195.0	436.5
Other	150.1	75.9	112.7
Current Liab.	400.4	424.5	681.5
Fix. Chg. Cov.	323%	309%	341%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.5%	10.0%	4.0%
"Cash Flow"	5.0%	7.0%	4.5%
Earnings	4.5%	6.5%	7.5%
Dividends	5.0%	4.5%	3.5%
Book Value	5.5%	6.0%	5.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2006	921.4	483.2	237.9	282.2	1924.7
2007	677.2	531.5	224.4	278.2	1711.3
2008	788.5	634.2	354.7	311.7	2089.1
2009	815	655	360	320	2150
2010	830	670	375	340	2215

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2006	.94	.57	d.16	d.08	1.27
2007	.94	.69	d.12	d.11	1.40
2008	1.12	.66	d.10	d.18	1.49
2009	1.13	.68	d.10	d.11	1.60
2010	1.15	.70	d.02	d.03	1.80

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.215	.23	.23	.23	.91
2006	.23	.24	.24	.24	.95
2007	.24	.25	.25	.25	.99
2008	.25	.26	.26	.26	1.03
2009	.26				

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 935,724 customers in North Carolina, South Carolina, and Tennessee. 2008 revenue mix: residential (39%), commercial (24%), industrial (12%), other (25%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 73.5% of revenues. '08 deprec. rate: 3.2%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,833 employees. Officers & directors own about 1.1% of common stock (1/09 proxy). Chairman, CEO, & President: Thomas E. Skains. Inc.: NC. Address: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas finished fiscal 2008 (ended October 31st) with solid results, despite the difficult economy. Revenues advanced 22% due to higher system throughput volumes, as well as additional customer accounts at the utility segment. However, the bottom-line increase was moderated owing to weaker contributions at the Southstar Energy Services unit. But progress was made.

The January-period bottom line came in slightly above the prior year. The top line benefited from additional customers in the residential, commercial, and conversion markets. Meanwhile, the Hardy Storage facility has begun to gain traction. It recently boosted its contribution to income by more than 20%. Margins were impacted last year because of declining natural gas prices, and a greater gas storage writedown than management expected. More recently, indications are that prices may start to help widen margins and boost earnings contributions from the nonutility portion of PNY's business mix.

Still, economic headwinds may weigh on this year's growth prospects. The past couple of quarters have experienced tapered growth in new accounts. And while these metrics are still relatively steady, the state of the regional economy suggests customer growth may slow further in the months to come. However, cost-cutting efforts ought to offset the slowdown and augur well for the bottom line, contributing to a share-net advance of roughly 7%.

We have introduced our 2010 earnings estimate at $1.80 a share. The continued utilization of Piedmont's Hardy Storage facility should provide a nice avenue for expansion next year. Meanwhile, it's only a matter of time before natural gas prices trend higher. And in the longer term, the Robeson liquefied natural gas storage project is slightly ahead of schedule and on budget to be in service by 2012.

These neutrally ranked shares may appeal to income-oriented accounts. Since our December review, they have declined approximately 21%. They still do not offer much in the way of capital appreciation potential. However, the recent downturn provides a more attractive entry point to this good-yielding stock.

Bryan Fong *March 13, 2009*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early May.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2008: $16.3 million, 22¢/share.
(E) In millions, adjusted for stock split.
(F) Quarters may not add to total due to change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	85

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SOUTH JERSEY INDS. NYSE-SJI

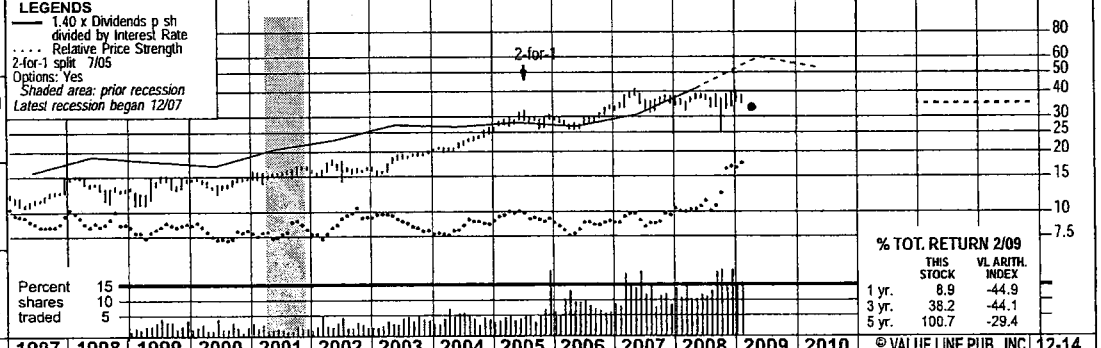
RECENT PRICE 33.42 | P/E RATIO 13.8 (Trailing: 14.7 Median: 14.0) | RELATIVE P/E RATIO 1.34 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 2 Raised 12/26/08
SAFETY 2 Lowered 1/4/91
TECHNICAL 2 Raised 3/6/09
BETA .65 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	15.4	15.4	15.1	17.0	18.3	20.3	26.5	32.4	34.3	41.3	40.6	40.8
Low:	11.0	10.8	12.3	13.8	14.1	15.3	19.7	24.9	25.6	31.2	25.2	32.8

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+50%)	13%
Low	35	(+5%)	5%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	1	0	0	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	2	1	0	0	0	0	2	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	57	85	71
to Sell	71	58	59
Hld's(000)	17182	17430	17041

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	6.9	-44.9
3 yr.	38.2	-44.1
5 yr.	100.7	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
17.03	17.45	16.50	16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	31.78	31.76	32.30	32.36	*32.80*	*33.55*	Revenues per sh	*36.35*
1.54	1.35	1.65	1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	3.51	3.20	3.27	*3.50*	*3.65*	"Cash Flow" per sh	*4.20*
.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.09	2.27	*2.45*	*2.65*	Earnings per sh A	*3.10*
.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.11	*1.20*	*1.28*	Div'ds Decl'd per sh B ■	*1.50*
1.87	1.93	2.08	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	3.21	2.51	1.88	2.08	*2.25*	*2.40*	Cap'l Spending per sh	*2.90*
7.17	7.23	7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.25	17.33	*18.35*	*19.35*	Book Value per sh C	*21.20*
19.61	21.43	21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	28.98	29.33	29.61	29.73	*30.50*	*31.00*	Common Shs Outst'g D	*33.00*
15.8	16.1	12.2	13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64	.91	.98	*Value Line*		Relative P/E Ratio	*.95*
5.9%	7.4%	7.2%	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $570.4 mill. Due in 5 Yrs $302.7 mill.
LT Debt $332.8 mill. LT Interest $17.0 mill.
(Total interest coverage: 6.0x)

Pension Assets-12/08 $88.3 mill. Oblig. $142.7 mill.

Pfd Stock none

Common Stock 29,738,256 common shs. as of 2/23/09

MARKET CAP: $1.0 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
392.5	515.9	837.3	505.1	696.8	819.1	921.0	931.4	956.4	962.0	*1000*	*1040*	Revenues ($mill)	*1200*
22.0	24.7	26.8	29.4	34.6	43.0	48.6	72.0	61.8	67.9	*75.0*	*80.0*	Net Profit ($mill)	*100.0*
42.8%	43.1%	42.2%	41.4%	40.6%	40.9%	41.5%	41.3%	41.9%	*43.3%*	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	7.1%	*7.5%*	*7.7%*	Net Profit Margin	*8.3%*
53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	44.9%	44.7%	42.7%	39.2%	*40.5%*	*40.5%*	Long-Term Debt Ratio	*40.5%*
37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	60.8%	*59.5%*	*59.5%*	Common Equity Ratio	*59.5%*
405.9	443.5	516.2	512.5	608.4	675.0	710.3	801.1	839.0	848.0	*945*	*1010*	Total Capital ($mill)	*1175*
533.3	562.2	607.0	666.6	748.3	799.9	877.3	920.0	948.9	982.6	*1015*	*1040*	Net Plant ($mill)	*1220*
7.4%	7.4%	6.9%	7.6%	7.3%	7.9%	8.3%	10.1%	8.6%	*8.5%*	*9.0%*	*9.0%*	Return on Total Cap'l	*10.0%*
11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	12.4%	16.3%	12.8%	13.2%	*13.5%*	*13.5%*	Return on Shr. Equity	*14.5%*
14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.2%	*13.5%*	*13.5%*	Return on Com Equity	*14.5%*
4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	6.2%	10.2%	6.7%	6.8%	*7.0%*	*6.5%*	Retained to Com Eq	*7.0%*
72%	67%	76%	62%	57%	52%	50%	37%	48%	49%	*49%*	*50%*	All Div'ds to Net Prof	*50%*

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	7.9	11.7	5.8
Other	363.8	316.6	429.3
Current Assets	371.7	328.3	435.1
Accts Payable	101.6	101.2	120.2
Debt Due	197.0	118.4	237.6
Other	124.2	108.7	142.1
Current Liab.	422.8	328.3	499.9
Fix. Chg. Cov.	527%	476%	598%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.0%	4.0%	*2.0%*
"Cash Flow"	7.0%	9.0%	*4.0%*
Earnings	9.5%	12.5%	*5.5%*
Dividends	2.5%	4.5%	*7.0%*
Book Value	7.5%	12.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	372.6	153.8	154.7	250.3	931.4
2007	368.4	171.7	156.2	260.1	956.4
2008	348.1	135.8	210.4	267.7	962.0
2009	*365*	*160*	*200*	*275*	*1000*
2010	*375*	*170*	*210*	*285*	*1040*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.06	.20	.51	.69	2.46
2007	1.30	.21	d.05	.63	2.09
2008	1.32	.26	.04	.67	2.27
2009	*1.35*	*.30*	*.10*	*.70*	*2.45*
2010	*1.40*	*.35*	*.15*	*.75*	*2.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	--	.213	.213	.438	.86
2006	--	.225	.225	.470	.92
2007	--	.245	.245	.515	1.01
2008	--	.270	.270	.568	1.11
2009					

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 340,136 customers in New Jersey's southern counties, which covers about 2,500 square miles and includes Atlantic City. Gas revenue mix '08: residential, 46%; commercial, 23%; cogeneration and electric generation, 6%; industrial, 25%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 602 employees. Off./dir. control 1.0% of com. shares; Dimensional Fund Advisors, 6.5%; Barclays, 6.1% (3/08 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have held up well in recent months. The company reported a solid bottom-line advance for the fourth quarter and full-year 2008. Its nonutility operations posted healthy growth at the Asset Management & Marketing unit. The utility segment has also benefited from increased customer conversions to natural gas and higher margins on off-system sales. The customer base increased by roughly 1.3% in 2008, despite a considerable slowdown in the new housing construction market.

The company has attractive prospects for the coming years. Natural gas remains the fuel of choice in the markets served by South Jersey Gas, where the fuel enjoys a significant price advantage over alternatives. Moreover, healthy performance should continue at South Jersey's nonutility operations. Overall, share earnings will probably advance at a nice clip in 2009.

South Jersey Gas recently filed two petitions with the New Jersey Board of Public Utilities advancing economic stimulus plans. The first accelerates into 2009 and 2010 roughly $100 million of capital spending on various utility infrastructure projects. The company is seeking to recover, and earn a return on, this investment through higher rates. The second petition proposes a $17 million Energy Efficiency Tracker that encourages energy conservation while allowing SJG to earn a competitive return. In addition, South Jersey plans to file a base rate case in early 2010, which will reflect approximately $380 million in capital investment since the last filing.

The company leased out its interest in the Marcellus Shale. It has formed an agreement with an exploration and production company to develop the deep mineral rights on over 21,000 acres of the Marcellus Shale in western Pennsylvania. This move will allow South Jersey to realize the value of this asset without incurring the costs of drilling the acreage itself.

This stock is timely. Earnings and dividend growth should continue to 2012-2014. However, this appears to be partly reflected in the current quotation. The yield on this good-quality issue is also below the average of the gas-utility group.

Michael Napoli, CPA *March 13, 2009*

(A) Based on GAAP EPS through 2006, economic earnings thereafter. GAAP EPS: '07, $2.10; '08, $2.58. Excl. nonrecur. gain (loss): '01, $0.13; '08, ($0.70). Excl gain (losses) from discont. ops.: '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02); '07, $0.01. Earnings may not sum due to rounding. Next egs. report due late April/early May. (B) Div'ds paid early Apr., Jul., Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. regulatory assets. In 2008: $270.4 mill., $9.10 per shr. (D) In millions, adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	75

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SOUTHWEST GAS NYSE-SWX

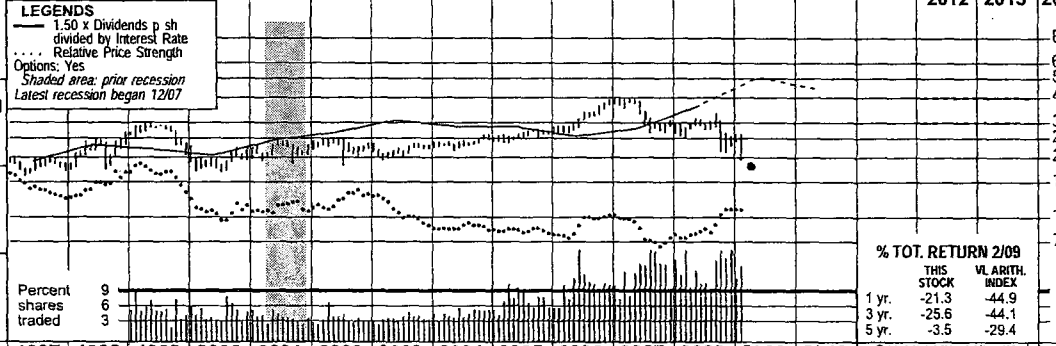
RECENT PRICE 18.15 | P/E RATIO 13.9 (Trailing: 12.9 Median: 18.0) | RELATIVE P/E RATIO 1.35 | DIV'D YLD 5.2% | VALUE LINE

TIMELINESS 3 Raised 5/23/08
SAFETY 3 Lowered 1/4/91
TECHNICAL 2 Raised 3/6/09
BETA .70 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	26.9	29.5	23.0	24.7	25.3	23.6	26.2	28.1	39.4	39.9	33.3	26.4
Low:	17.3	20.4	16.9	18.6	18.1	19.3	21.5	23.5	26.0	26.5	21.1	18.1

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+120%)	25%
Low	30	(+65%)	17%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	2	1	1	0
Options	0	1	0	0	0	0	0	0	0
to Sell	0	3	0	0	0	2	0	0	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	80	85	69
to Sell	88	65	74
Hld's(000)	34496	34150	33669

Percent shares traded 9 6 3

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-21.3	-44.9
3 yr.	-25.6	-44.1
5 yr.	-3.5	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
25.68	28.16	23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	*44.45*	*46.75*	Revenues per sh	*55.00*
3.24	5.09	2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	*5.75*	*6.05*	*6.65*	"Cash Flow" per sh	*7.50*
.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	*1.50*	*1.85*	Earnings per sh A	*2.30*
.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	*.95*	*1.00*	Div'ds Decl'd per sh B■†	*1.15*
5.43	6.64	6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	*7.00*	*7.20*	Cap'l Spending per sh	*9.00*
15.96	16.38	14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.48	*24.45*	*25.00*	Book Value per sh	*26.00*
21.00	21.28	24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	*45.00*	*46.00*	Common Shs Outst'g C	*50.00*
26.5	14.0	NMF	NMF	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
1.57	.92	NMF	NMF	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.25	*Value Line*		Relative P/E Ratio	*1.00*
4.4%	4.7%	5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 12/31/08

Total Debt $1348.3 mill. **Due in 5 Yrs** $624.0 mill.
LT Debt $1285.5 mill. **LT Interest** $90.0 mill.
(Total interest coverage: 2.1x)
Leases, Uncapitalized Annual rentals $6.0 mill.
Pension Assets-12/08 $342.9 mill. **Oblig.** $558.9 mill.
Pfd Stock None

Common Stock 44,436,610 shs. as of 2/17/09

MARKET CAP: $800 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
936.9	1034.1	1396.7	1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	*2000*	*2150*	Revenues ($mill)	*2750*
39.3	38.3	37.2	38.6	38.5	58.9	48.1	80.5	83.2	61.0	*67.5*	*85.0*	Net Profit ($mill)	*115*
35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	*38.0%*	*38.0%*	Income Tax Rate	*36.0%*
4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	*3.4%*	*4.0%*	Net Profit Margin	*4.2%*
60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	*53.5%*	*52.5%*	Long-Term Debt Ratio	*51.0%*
35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	44.7%	*46.5%*	*47.5%*	Common Equity Ratio	*49.0%*
1424.7	1489.9	1417.6	1748.3	1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	*2375*	*2425*	Total Capital ($mill)	*2650*
1581.1	1686.1	1825.6	1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	*3100*	*3250*	Net Plant ($mill)	*3700*
4.8%	4.6%	5.1%	4.3%	4.2%	5.0%	4.3%	5.5%	5.5%	*4.5%*	*4.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	*6.0%*	*7.5%*	Return on Shr. Equity	*9.0%*
7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	*6.0%*	*7.5%*	Return on Com Equity	*9.0%*
2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	*2.5%*	*3.5%*	Retained to Com Eq	*4.5%*
64%	67%	71%	70%	72%	49%	65%	42%	44%	63%	*63%*	*54%*	All Div'ds to Net Prof	*50%*

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	18.8	32.0	26.4
Other	482.8	470.5	411.7
Current Assets	501.6	502.5	438.1
Accts Payable	265.7	220.7	191.4
Debt Due	27.5	47.1	62.8
Other	202.9	260.1	255.7
Current Liab.	496.1	527.9	509.9
Fix. Chg. Cov.	220%	229%	224%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.0%	4.5%	*2.0%*
"Cash Flow"	6.0%	4.0%	*4.0%*
Earnings	16.5%	8.0%	*4.5%*
Dividends	--	.5%	*5.0%*
Book Value	4.0%	4.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	676.9	430.9	351.8	565.1	2024.7
2007	793.7	426.6	371.5	560.3	2152.1
2008	813.6	447.3	374.4	509.4	2144.7
2009	*790*	*400*	*310*	*500*	*2000*
2010	*810*	*440*	*350*	*550*	*2150*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.11	.02	d.26	1.11	1.98
2007	1.17	d.01	d.22	1.01	1.95
2008	1.14	d.06	d.38	.71	1.39
2009	*1.00*	*d.05*	*d.35*	*.90*	*1.50*
2010	*1.05*	*Nil*	*d.30*	*1.10*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.205	.205	.205	.205	.82
2006	.205	.205	.205	.205	.82
2007	.205	.215	.215	.215	.85
2008	.215	.225	.225	.225	.89
2009	.225	.238			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.8 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2008 margin mix: residential and small commercial, 86%; large commercial and industrial, 5%; transportation, 9%. Total throughput: 2.4 billion therms. Sold PriMerit Bank, 7/96. Has 4,732 employees. Off. & Dir. own 1.8% of common stock; T. Rowe Price Associates, Inc., 6.7%; GAMCO Investors, Inc., 5.8% (3/08 Proxy). Chairman: James J. Kropid. Chief Executive Officer: Jeffrey W. Shaw. Inc.: California. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Shares of Southwest Gas have traded lower in the past six months. Share earnings for 2008 came in well below the prior-year tally. Customer growth dropped to its lowest level in over two decades, owing to the prolonged housing slowdown in the Southwest. This has also hurt performance at construction subsidiary NPL. Looking forward, the business environment will probably remain challenging in 2009. Thus, we anticipate unimpressive results for the current year, too. Operating performance may well improve in 2010, assuming success at controlling costs and an economic rebound.

The company has announced two rate case settlements. In Arizona, Southwest Gas was granted an annual rate increase of $33.5 million, which was somewhat less than the $50.2 million SWX had been seeking. Elsewhere, higher rates in California became effective in January. Looking ahead, Southwest is preparing to file a rate case in Nevada during the second quarter. The company's focus on obtaining rate relief and improving rate design is important, as it depends upon such improved revenue increases to help it cope with higher expenses.

Southwest Gas has announced a dividend increase. Starting in June, the quarterly dividend will be $0.2375 per share, almost 6% higher than the most recent payout. This follows similar increases in the past two years. This pattern is encouraging, and may well continue going forward.

Investors should be mindful of several caveats. Warmer-than-normal temperatures during the winter months can hinder profitability at Southwest Gas. Further efforts to expand operations would probably be accompanied by greater operating costs, too. Moreover, insufficient, or lagging, rate relief can hurt performance.

These shares are not a standout for the coming six to 12 months. Market conditions will likely continue to stymie growth at Southwest Gas in the near term. Looking further out, we anticipate higher earnings by 2012-2014. Moreover, this issue's healthy dividend yield may appeal to income-oriented investors. From the current quotation, this stock has good total return potential for a utility.

Michael Napoli, CPA *March 13, 2009*

(A) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Incl. asset writedown: '93, 44¢. Excl. loss from disc. ops.: '95, 75¢. Totals may not sum due to rounding. Next egs. report due early May. (B) Dividends historically paid early March, June, September, December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions.

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	70

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WGL HOLDINGS NYSE-WGL

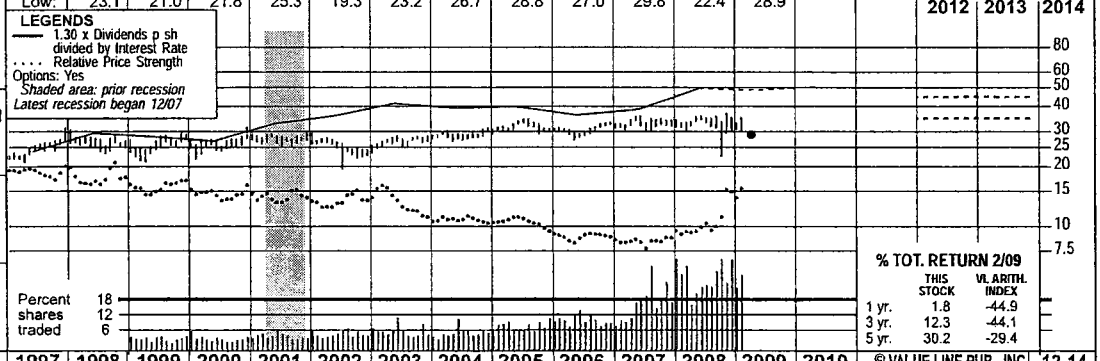
RECENT PRICE **28.99** | P/E RATIO **11.6** (Trailing: 11.5 Median: 15.0) | RELATIVE P/E RATIO **1.13** | DIV'D YLD **5.0%** | VALUE LINE

TIMELINESS **2** Raised 2/13/09
SAFETY **1** Raised 4/2/93
TECHNICAL **2** Raised 3/6/09
BETA .65 (1.00 = Market)

High:	30.8	29.4	31.5	30.5	29.5	28.8	31.4	34.8	33.6	35.9	37.1	35.5
Low:	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8	27.0	29.8	22.4	28.9

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	55%	15%
Low	35	20%	9%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	1	0	0	0	0	0	0	0
Options	0	5	1	0	0	2	0	4	0
to Sell	0	7	1	0	0	2	0	4	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	106	95	83
to Sell	89	100	119
Hld's(000)	35559	34195	32939

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.8	-44.9
3 yr.	12.3	-44.1
5 yr.	30.2	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
21.55	21.69	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	53.50	54.60	Revenues per sh A	57.90
2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.89	3.89	4.34	4.40	4.45	"Cash Flow" per sh	4.70
1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.10	2.44	2.50	2.55	Earnings per sh B	2.75
1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	1.45	1.50	Div'ds Decl'd per sh C■	1.60
2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	3.00	3.00	Cap'l Spending per sh	2.50
11.04	11.51	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	22.05	23.10	Book Value per sh D	26.45
41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	50.00	50.00	Common Shs Outst'g E	50.00
15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	Bold figures are		Avg Ann'l P/E Ratio	15.0
.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.82	.85	Value Line		Relative P/E Ratio	1.00
5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	estimates		Avg Ann'l Div'd Yield	4.2%

CAPITAL STRUCTURE as of 12/31/08
Total Debt $1073.0 mill. Due in 5 Yrs $264.5 mill.
LT Debt $657.7 mill. LT Interest $37.4 mill.
(LT interest earned: 5.9x; total interest coverage: 5.2x)
Pension Assets-9/08 $588.2 mill. Oblig. $590.5 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 50,124,429 shs. as of 1/31/09

MARKET CAP: $1.5 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
972.1	1031.1	1446.5	1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	2675	2730	Revenues ($mill) A	2895
68.8	84.6	89.9	55.7	112.3	98.0	104.8	96.0	102.9	122.9	125	130	Net Profit ($mill)	140
36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	37.0%	37.0%	Income Tax Rate	38.0%
7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	4.7%	4.7%	Net Profit Margin	4.8%
41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	36.5%	35.5%	Long-Term Debt Ratio	34.0%
56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	62.0%	63.0%	Common Equity Ratio	64.5%
1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	1526.1	1625.4	1679.5	1780	1835	Total Capital ($mill)	2050
1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	2325	2420	Net Plant ($mill)	2720
7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	8.0%	8.0%	Return on Total Cap'l	8.0%
9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	11.5%	11.0%	Return on Shr. Equity	10.5%
9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	12.0%	11.5%	Return on Com Equity	11.0%
1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	4.5%	4.5%	Retained to Com Eq	4.5%
82%	69%	67%	112%	56%	65%	62%	69%	66%	57%	57%	57%	All Div'ds to Net Prof	58%

CURRENT POSITION ($MILL.)	2007	2008	12/31/08
Cash Assets	4.9	6.2	8.8
Other	568.8	736.1	1066.3
Current Assets	573.7	742.3	1075.1
Accts Payable	216.9	243.1	326.9
Debt Due	205.4	347.0	415.3
Other	134.8	158.4	271.8
Current Liab.	557.1	748.5	1014.0
Fix. Chg. Cov.	432%	490%	500%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.5%	9.0%	1.5%
"Cash Flow"	3.5%	4.0%	2.5%
Earnings	2.0%	4.0%	4.0%
Dividends	1.5%	1.5%	2.5%
Book Value	4.0%	4.5%	5.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	902.9	1064.5	346.9	323.6	2637.9
2007	732.9	1119.9	467.5	325.7	2646.0
2008	751.6	1020.0	464.7	391.9	2628.2
2009	821.5	1024	469.5	360	2675
2010	835	1040	485	370	2730

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.93	1.17	d.01	d.15	1.94
2007	.92	1.27	.22	d.31	2.10
2008	.96	1.66	.06	d.24	2.44
2009	1.03	1.50	.15	d.18	2.50
2010	1.05	1.50	.15	d.15	2.55

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.325	.333	.333	.333	1.32
2006	.333	.338	.338	.338	1.34
2007	.34	.34	.34	.34	1.36
2008	.34	.36	.36	.36	1.42
2009	.36				

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,053,032 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. American Century Inv. own 7.1% of common stock; Off./dir. less than 1% (1/09 proxy). Chrmn. & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Addr.: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings started fiscal 2009 (began October 1st) on a high note. Its regulated utility business gained roughly 7,500 active metered accounts over the year-ago period. And the retail energy marketing segment's contribution to revenues and earnings got a boost from higher realized margins on the sale of natural gas. These items contributed nicely to the 9% top-line volume advance. Meanwhile, decreased labor and benefit costs, due to outsourcing, benefited margins. However, offsetting factors included a slowing of natural gas and electric volumes owing to a reduced number of customers at the retail energy segment. Still, in all, WGL's bottom line advanced 7.3% over this timeframe.

However, March-interim share net will likely fall short compared to the previous year. Over the past 12 months, WGL has initiated decoupling programs in both Virginia and the DC areas to help minimize the effects of weather and usage on its financial results. Thus, last year's second quarter benefited from increased consumption levels whereas 2008's has not. Moving forward, decoupling creates a smoothing effect on the bottom line, and ought to reduce earnings volatility.

On balance, though, the company ought to see its profits rise roughly 3% this year. The regulated utility segment ought to continue to benefit from additional active meters. However, many in this industry have been experiencing a moderation in new accounts. This stems from the sharp recessionary environment that has pushed up home foreclosures. Furthermore, natural gas consumption patterns may decline throughout all service areas as consumers try to cut monthly spending. Still, with over one million active meters, WGL appears to be in good shape to weather this economic storm.

These high-quality shares have provided a bit of a safe haven, as they have held up better than most stocks since our December review. They are also ranked to outperform the broader market in the coming year. What's more, dividend growth is a hallmark here. On the downside, WGL offers minimal appreciation potential for the coming 3 to 5 years, but this is typical for most utilities.

Bryan Fong *March 13, 2009*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late April. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '08: $291.3 million, $5.81/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	75

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ATTACHMENT C

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

AMERICAN STS WTR CO (NYSE)

Scottrade

AWR	31.35	▼-0.20	(-0.63%)	Vol. 256,519	16:00 ET

American States is a public utility company engaged principally in thepurchase, production, distribution and sale of water. The company alsodistributes electricity in some communities. In the customer service areas for both water and electric, rates and operations are subject to the jurisdiction of the California Public Utilities Commission.

General Information

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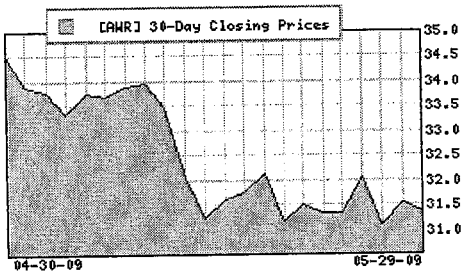
Email: investorinfo@aswater.com

Industry	UTIL-WATER SPLY
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	08/06/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	31.55
52 Week High	42.00
52 Week Low	27.00
Beta	0.41
20 Day Moving Average	168,721.91
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-9.21	4 Week	-13.79
12 Week	-0.60	12 Week	-26.19
YTD	-4.94	YTD	-3.29

Share Information		Dividend Information	
Shares Outstanding (millions)	17.32	Dividend Yield	3.19%
		Annual Dividend	$1.00
Market Capitalization (millions)	542.92	Payout Ratio	0.62
		Change in Payout Ratio	0.00
Short Ratio	2.55	Last Dividend Payout / Amount	05/07/2009 / $0.25
Last Split Date	06/10/2002		

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.44	Current (1=Strong Buy, 5=Strong Sell)	1.67
Current Year EPS Consensus Estimate	1.66	30 Days Ago	2.33
Estimated Long-Term EPS Growth Rate	8.70	60 Days Ago	2.00
Next EPS Report Date	08/06/2009	90 Days Ago	1.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	18.85	vs. Previous Year	-6.67%	vs. Previous Year	15.47%
Trailing 12 Months:	19.47	vs. Previous Quarter	-30.00%	vs. Previous Quarter:	-5.45%
PEG Ratio	2.17				

Price Ratios		ROE		ROA	
Price/Book	1.74	03/31/09	9.02	03/31/09	2.68

Price/Cash Flow	8.33	12/31/08	9.20	12/31/08	2.80
Price / Sales	1.65	09/30/08	8.97	09/30/08	2.77
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	0.82	03/31/09	0.80	03/31/09	8.51
12/31/08	0.66	12/31/08	0.64	12/31/08	8.91
09/30/08	0.57	09/30/08	0.55	09/30/08	8.91
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	9.75	03/31/09	9.75	03/31/09	18.01
12/31/08	11.10	12/31/08	11.10	12/31/08	17.96
09/30/08	14.27	09/30/08	14.27	09/30/08	18.02
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	52.72	03/31/09	0.98	03/31/09	49.56
12/31/08	54.08	12/31/08	0.86	12/31/08	46.19
09/30/08	59.72	09/30/08	0.86	09/30/08	46.19

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

CALIFORNIA WTR SVC GROUP (NYSE)

Scottrade

CWT	34.82	▲0.38	(1.10%)	Vol. 159,092	16:05 ET

California Water Service Company's business, which is carried on through its operating subsidiaries, consists of the production, purchase, storage, purification, distribution and sale of water for domestic, industrial, public and irrigation uses, and for fire protection. It also provides water related services under agreements with municipalities and other private companies. The nonregulated services include full water system operation, and billing and meter reading services.

General Information

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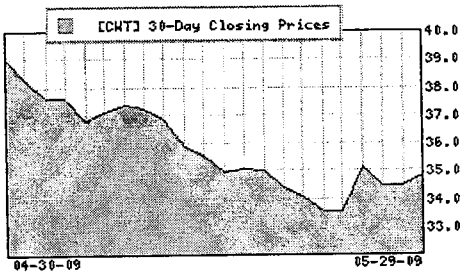
Industry	UTIL-WATER SPLY
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	07/22/2009

Price and Volume Information

Zacks Rank	2
Yesterday's Close	34.44
52 Week High	48.28
52 Week Low	27.68
Beta	0.55
20 Day Moving Average	168,056.95
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-10.79	4 Week	-15.28
12 Week	-7.96	12 Week	-31.65
YTD	-25.01	YTD	-26.44

Share Information		Dividend Information	
Shares Outstanding (millions)	20.72	Dividend Yield	3.39%
		Annual Dividend	$1.18
Market Capitalization (millions)	721.61	Payout Ratio	0.59
Short Ratio	2.62	Change in Payout Ratio	-0.19
Last Split Date	01/26/1998	Last Dividend Payout / Amount	05/06/2009 / $0.29

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.53	Current (1=Strong Buy, 5=Strong Sell)	2.17
Current Year EPS Consensus Estimate	2.07	30 Days Ago	2.50
Estimated Long-Term EPS Growth Rate	8.00	60 Days Ago	2.57
Next EPS Report Date	07/22/2009	90 Days Ago	2.29

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.81	vs. Previous Year	1,100.00%	vs. Previous Year	18.78%
Trailing 12 Months:	17.32	vs. Previous Quarter	-65.71%	vs. Previous Quarter:	-13.48%
PEG Ratio	2.10				

Price Ratios	ROE		ROA		
Price/Book	1.81	03/31/09	10.58	03/31/09	3.14
Price/Cash Flow	9.02	12/31/08	10.14	12/31/08	3.10
Price / Sales	1.70	09/30/08	9.99	09/30/08	3.14
Current Ratio	**Quick Ratio**		**Operating Margin**		
03/31/09	0.56	03/31/09	0.52	03/31/09	9.92
12/31/08	0.65	12/31/08	0.61	12/31/08	9.70
09/30/08	0.57	09/30/08	0.54	09/30/08	9.81
Net Margin	**Pre-Tax Margin**		**Book Value**		
03/31/09	15.95	03/31/09	15.95	03/31/09	19.28
12/31/08	15.67	12/31/08	15.67	12/31/08	19.45
09/30/08	-	09/30/08	-	09/30/08	19.37
Inventory Turnover	**Debt-to-Equity**		**Debt to Capital**		
03/31/09	36.94	03/31/09	0.72	03/31/09	41.82
12/31/08	34.10	12/31/08	0.71	12/31/08	41.64
09/30/08	-	09/30/08	0.72	09/30/08	41.83

Zacks.com Quotes and Research

Scottrade

AQUA AMERICA INC (NYSE)

WTR	16.49	-0.16	(-0.96%)	Vol. 904,419	16:04 ET

Aqua America is the largest publicly-traded U.S.-based water utility serving residents in Pennsylvania, Ohio, Illinois, Texas, New Jersey, Indiana, Virginia, Florida, North Carolina, Maine, Missouri, New York, South Carolina and Kentucky. The company has been committed to the preservation and improvement of the environment throughout its history, which spans more than 100 years.

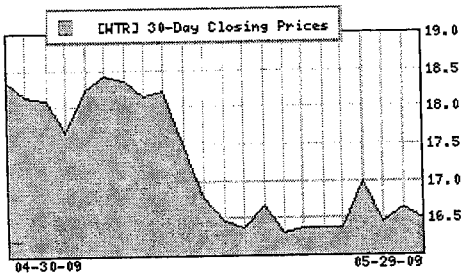
General Information

AQUA AMER INC
762 W Lancaster Avenue
Bryn Mawr, PA 19010-3489
Phone: 610 527-8000
Fax: 610-645-1061
Web: www.suburbanwater.com
Email: ir.aquaamerica.com

Industry	UTIL-WATER SPLY
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	08/05/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	16.65
52 Week High	22.00
52 Week Low	12.20
Beta	0.23
20 Day Moving Average	1,107,139.38
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-10.14	4 Week	-14.67
12 Week	-9.64	12 Week	-32.90
YTD	-19.91	YTD	-19.04

Share Information		Dividend Information	
Shares Outstanding (millions)	135.41	Dividend Yield	3.27%
		Annual Dividend	$0.54
Market Capitalization (millions)	2,232.96	Payout Ratio	0.71
		Change in Payout Ratio	0.07
Short Ratio	12.63	Last Dividend Payout / Amount	05/14/2009 / $0.14
Last Split Date	12/02/2005		

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.20	Current (1=Strong Buy, 5=Strong Sell)	2.11
Current Year EPS Consensus Estimate	0.83	30 Days Ago	2.38
Estimated Long-Term EPS Growth Rate	8.30	60 Days Ago	2.22
Next EPS Report Date	08/05/2009	90 Days Ago	2.22

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	19.78	vs. Previous Year	27.27%	vs. Previous Year	10.92%
Trailing 12 Months:	21.70	vs. Previous Quarter	-26.32%	vs. Previous Quarter:	-3.35%
PEG Ratio	2.39				

Price Ratios	ROE	ROA

Price/Book	2.10	03/31/09	9.77	03/31/09	2.99
Price/Cash Flow	11.57	12/31/08	9.58	12/31/08	2.93
Price / Sales	3.48	09/30/08	9.70	09/30/08	2.96
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	0.60	03/31/09	0.55	03/31/09	15.87
12/31/08	0.63	12/31/08	0.58	12/31/08	15.62
09/30/08	0.59	09/30/08	0.54	09/30/08	15.77
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	26.37	03/31/09	26.37	03/31/09	7.86
12/31/08	25.92	12/31/08	25.92	12/31/08	7.85
09/30/08	25.94	09/30/08	25.94	09/30/08	7.62
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	31.95	03/31/09	1.15	03/31/09	53.52
12/31/08	24.96	12/31/08	1.18	12/31/08	54.15
09/30/08	6.51	09/30/08	1.18	09/30/08	54.14

Zacks.com Quotes and Research

AGL RESOURCES INC (NYSE)

Scottrade

AGL	28.46	▼-0.16	(-0.56%)	Vol. 229,976	16:02 ET

AGL Resources principal business is the distribution of natural gas to customers in central, northwest, northeast and southeast Georgia and the Chattanooga, Tennessee area through its natural gas distribution subsidiary. AGL's major service area is the ten county metropolitan Atlanta area.

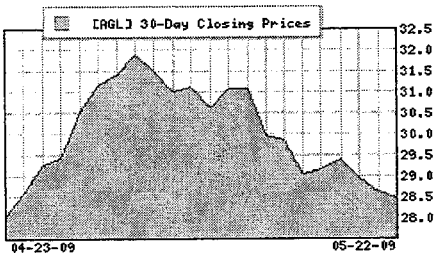
General Information

AGL RESOURCES
Ten Peachtree Place NE
Atlanta, GA 30309
Phone: 404 584-4000
Fax: 404 584-3945
Web: www.aglresources.com
Email: scave@aglresources.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	07/23/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	28.62
52 Week High	36.42
52 Week Low	24.02
Beta	0.43
20 Day Moving Average	453,827.84
Target Price Consensus	33.75



% Price Change		% Price Change Relative to S&P 500	
4 Week	1.50	4 Week	-2.52
12 Week	2.04	12 Week	-13.39
YTD	-9.22	YTD	-5.30

Share Information		Dividend Information	
Shares Outstanding (millions)	77.09	Dividend Yield	6.04%
		Annual Dividend	$1.72
Market Capitalization (millions)	2,193.90	Payout Ratio	0.55
Short Ratio	3.45	Change in Payout Ratio	-0.02
Last Split Date	12/04/1995	Last Dividend Payout / Amount	05/13/2009 / $0.43

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.22	Current (1=Strong Buy, 5=Strong Sell)	2.20
Current Year EPS Consensus Estimate	2.68	30 Days Ago	2.20
Estimated Long-Term EPS Growth Rate	5.30	60 Days Ago	2.20
Next EPS Report Date	07/23/2009	90 Days Ago	2.17

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	10.62	vs. Previous Year	33.62%	vs. Previous Year	-1.68%
Trailing 12 Months:	9.18	vs. Previous Quarter	59.79%	vs. Previous Quarter:	23.60%
PEG Ratio	1.99				

Price Ratios		ROE		ROA	
Price/Book	1.24	03/31/09	13.92	03/31/09	3.66

Price/Cash Flow	6.08	12/31/08	12.23	12/31/08	3.20
Price / Sales	0.79	09/30/08	11.74	09/30/08	3.13
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.06	03/31/09	0.80	03/31/09	8.53
12/31/08	1.03	12/31/08	0.70	12/31/08	7.41
09/30/08	1.06	09/30/08	0.62	09/30/08	7.44
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	14.84	03/31/09	14.84	03/31/09	22.87
12/31/08	12.46	12/31/08	12.46	12/31/08	21.52
09/30/08	12.43	09/30/08	12.43	09/30/08	22.49
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	3.45	03/31/09	0.95	03/31/09	48.72
12/31/08	3.35	12/31/08	1.01	12/31/08	50.82
09/30/08	2.77	09/30/08	0.97	09/30/08	49.71

Zacks.com Quotes and Research

ATMOS ENERGY CORP (NYSE)

Scottrade

ATO	23.91	▼-0.15	(-0.62%)	Vol. 290,909	16:03 ET

Atmos Energy Corporation distributes and sells natural gas to residential, commercial, industrial, agricultural and other customers. Atmos operates through five divisions in cities, towns and communities in service areas located in Colorado, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Missouri, South Carolina, Tennessee, Texas and Virginia. The Company has entered into an agreement to sell all of its natural gas utility operations in South Carolina. The Company also transports natural gas for others through its distribution system.

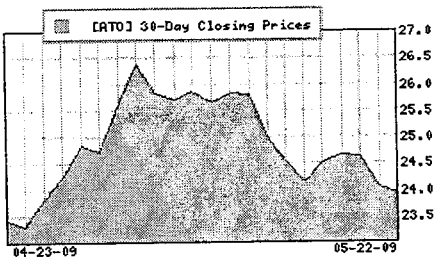
General Information

ATMOS ENERGY CP
Three Lincoln Centre 5430 Lbj Freeway
Suite 1800
Dallas, TX 75240
Phone: 972-934-9227
Fax: 972-855-3040
Web: www.atmosenergy.com
Email: InvestorRelations@atmosenergy.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	08/04/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	24.06
52 Week High	28.66
52 Week Low	19.68
Beta	0.52
20 Day Moving Average	664,797.38
Target Price Consensus	28.42



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.05	4 Week	-1.99
12 Week	7.75	12 Week	-8.55
YTD	0.89	YTD	4.16

Share Information		Dividend Information	
Shares Outstanding (millions)	91.91	Dividend Yield	5.52%
Market Capitalization (millions)	2,197.66	Annual Dividend	$1.32
Short Ratio	2.42	Payout Ratio	0.63
Last Split Date	05/17/1994	Change in Payout Ratio	-0.03
		Last Dividend Payout / Amount	02/23/2009 / $0.33

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	-0.10	Current (1=Strong Buy, 5=Strong Sell)	2.57
Current Year EPS Consensus Estimate	2.08	30 Days Ago	2.57
Estimated Long-Term EPS Growth Rate	5.80	60 Days Ago	2.57
Next EPS Report Date	08/04/2009	90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.49	vs. Previous Year	7.26%	vs. Previous Year	-26.67%
Trailing 12 Months:	11.33	vs. Previous Quarter	60.24%	vs. Previous Quarter:	6.12%
PEG Ratio	1.97				

Price Ratios	ROE		ROA		
Price/Book	1.01	03/31/09	9.16	03/31/09	2.93
Price/Cash Flow	5.69	12/31/08	8.73	12/31/08	2.81
Price / Sales	0.33	09/30/08	8.67	09/30/08	2.82
Current Ratio	**Quick Ratio**		**Operating Margin**		
03/31/09	1.15	03/31/09	0.90	03/31/09	2.91
12/31/08	0.83	12/31/08	0.55	12/31/08	2.51
09/30/08	1.06	09/30/08	0.59	09/30/08	2.50
Net Margin	**Pre-Tax Margin**		**Book Value**		
03/31/09	4.61	03/31/09	4.61	03/31/09	23.70
12/31/08	4.05	12/31/08	4.05	12/31/08	22.70
09/30/08	4.05	09/30/08	4.05	09/30/08	22.65
Inventory Turnover	**Debt-to-Equity**		**Debt to Capital**		
03/31/09	11.66	03/31/09	1.00	03/31/09	49.89
12/31/08	12.20	12/31/08	0.83	12/31/08	45.28
09/30/08	11.99	09/30/08	1.03	09/30/08	50.81

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

LACLEDE GROUP INC (NYSE)

Scottrade

LG	29.80	-0.35	(-1.16%)	Vol. 133,326	16:03 ET

The Laclede Group, Inc. is a public utility engaged in the retail distribution and transportation of natural gas. The Company, which is subject to the jurisdiction of the Missouri Public Service Commission, serves the City of St. Louis, St. Louis County, the City of St. Charles, St. Charles County, the town of Arnold, and parts of Franklin, Jefferson, St. Francois, Ste. Genevieve, Iron, Madison and Butler Counties, all in Missouri.

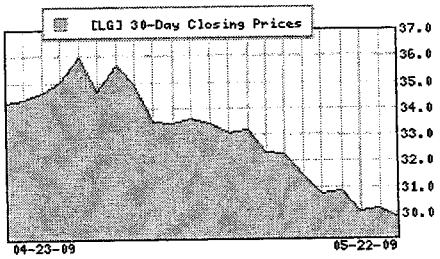
General Information

LACLEDE GRP INC
720 Olive Street
St. Louis, MO 63101
Phone: 314-342-0500
Fax: 314-421-1979
Web: www.thelacledegroup.com
Email: mkullman@lacledegas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	07/24/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	30.15
52 Week High	55.81
52 Week Low	29.75
Beta	0.09
20 Day Moving Average	208,767.66
Target Price Consensus	40



% Price Change		% Price Change Relative to S&P 500	
4 Week	-12.97	4 Week	-16.41
12 Week	-26.29	12 Week	-37.44
YTD	-36.38	YTD	-31.48

Share Information		Dividend Information	
Shares Outstanding (millions)	22.14	Dividend Yield	5.17%
		Annual Dividend	$1.54
Market Capitalization (millions)	659.62	Payout Ratio	0.50
Short Ratio	3.23	Change in Payout Ratio	-0.15
Last Split Date	03/08/1994	Last Dividend Payout / Amount	03/09/2009 / $0.38

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.34	Current (1=Strong Buy, 5=Strong Sell)	3.25
Current Year EPS Consensus Estimate	2.94	30 Days Ago	3.25
Estimated Long-Term EPS Growth Rate	6.50	60 Days Ago	3.25
Next EPS Report Date	07/24/2009	90 Days Ago	3.25

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	10.14	vs. Previous Year	0.72%	vs. Previous Year	-11.85%
Trailing 12 Months:	9.61	vs. Previous Quarter	-1.41%	vs. Previous Quarter:	-2.25%
PEG Ratio	1.56				

Price Ratios		ROE		ROA	
Price/Book	1.24	03/31/09	13.53	03/31/09	3.89

Price/Cash Flow	6.93	12/31/08	13.74	12/31/08	3.89
Price / Sales	0.29	09/30/08	12.04	09/30/08	3.35
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.17	03/31/09	0.95	03/31/09	2.97
12/31/08	1.14	12/31/08	0.74	12/31/08	2.83
09/30/08	1.17	09/30/08	0.69	09/30/08	2.53
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	4.46	03/31/09	4.46	03/31/09	24.11
12/31/08	4.20	12/31/08	4.20	12/31/08	22.98
09/30/08	3.79	09/30/08	3.79	09/30/08	22.14
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	11.31	03/31/09	0.73	03/31/09	42.17
12/31/08	12.61	12/31/08	0.77	12/31/08	43.33
09/30/08	13.28	09/30/08	0.80	09/30/08	44.42

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

Scottrade

NEW JERSEY RES (NYSE)

NJR	32.33	▼-0.06	(-0.19%)	Vol. 218,797	16:00 ET

NJ RESOURCES is an exempt energy svcs holding company providing retail & wholesale natural gas & related energy services to customers from the Gulf Coast to New England. Subsidiaries include: (1) N J Natural Gas Co, a natural gas distribution company that provides regulated energy & appliance services to residential, commercial & industrial customers in central & northern N J. (2) NJR Energy Holdings Corp formerly NJR Energy Svcs Corp & (3) NJR Development Corp, a sub-holding company of NJR, which includes the Company's remaining unregulated operating subsidiaries.

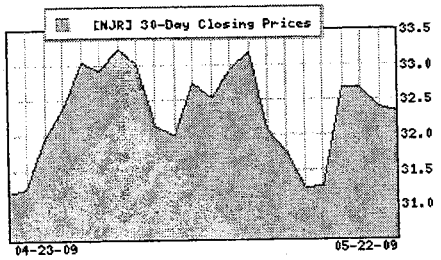
General Information

NJ RESOURCES
1415 Wyckoff Road
Wall, NJ 07719
Phone: 732-938-1489
Fax: 732 938-3154
Web: www.njresources.com
Email: investcont@njresources.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	07/22/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.39
52 Week High	42.37
52 Week Low	21.90
Beta	0.16
20 Day Moving Average	536,252.06
Target Price Consensus	43



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.75	4 Week	-0.35
12 Week	-8.98	12 Week	-22.75
YTD	-17.84	YTD	-18.78

Share Information		Dividend Information	
Shares Outstanding (millions)	42.32	Dividend Yield	3.84%
Market Capitalization (millions)	1,368.17	Annual Dividend	$1.24
Short Ratio	3.34	Payout Ratio	0.63
Last Split Date	03/04/2008	Change in Payout Ratio	0.12
		Last Dividend Payout / Amount	03/11/2009 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.02	Current (1=Strong Buy, 5=Strong Sell)	1.67
Current Year EPS Consensus Estimate	2.39	30 Days Ago	1.67
Estimated Long-Term EPS Growth Rate	8.00	60 Days Ago	1.67
Next EPS Report Date	07/22/2009	90 Days Ago	2.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.53	vs. Previous Year	-8.60%	vs. Previous Year	-20.38%
Trailing 12 Months:	16.41	vs. Previous Quarter	123.68%	vs. Previous Quarter:	17.00%
PEG Ratio	1.69				

Price Ratios		ROE		ROA	
Price/Book	1.81	03/31/09	11.73	03/31/09	3.25
Price/Cash Flow	10.20	12/31/08	12.89	12/31/08	3.48
Price / Sales	0.38	09/30/08	13.77	09/30/08	3.74
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.17	03/31/09	1.07	03/31/09	2.37
12/31/08	1.17	12/31/08	0.76	12/31/08	2.36
09/30/08	1.24	09/30/08	0.70	09/30/08	2.46
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	5.26	03/31/09	5.26	03/31/09	17.90
12/31/08	3.89	12/31/08	3.89	12/31/08	17.49
09/30/08	4.72	09/30/08	4.72	09/30/08	17.29
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	10.09	03/31/09	0.61	03/31/09	37.74
12/31/08	9.51	12/31/08	0.63	12/31/08	38.48
09/30/08	9.16	09/30/08	0.63	09/30/08	38.50

Zacks.com Quotes and Research

NICOR INC (NYSE) Scottrade

GAS	30.90	▼-0.18	(-0.58%)	Vol. 288,557	16:01 ET

Nicor Inc. is a holding company and is a member of the Standard & Poor's 500 Index. Its primary business is Nicor Gas, one of the nation's largest natural gas distribution companies. Nicor owns Tropical Shipping, a containerized shipping business serving the Caribbean region and the Bahamas. In addition, the company owns and has an equity interest in several energy-related businesses.

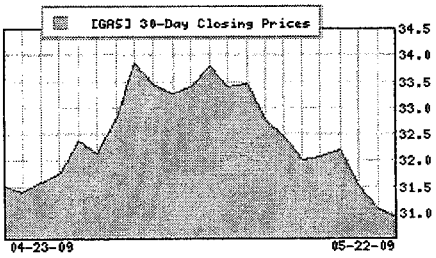
General Information

NICOR INC
1844 Ferry Road
Naperville, IL 60563-9600
Phone: 630-305-9500
Fax: 630-983-9328
Web: www.nicor.com
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	08/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	31.08
52 Week High	51.99
52 Week Low	27.50
Beta	0.36
20 Day Moving Average	519,217.91
Target Price Consensus	40.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.94	4 Week	-5.81
12 Week	-2.43	12 Week	-17.19
YTD	-11.05	YTD	-5.73

Share Information		Dividend Information	
Shares Outstanding (millions)	45.20	Dividend Yield	6.02%
		Annual Dividend	$1.86
Market Capitalization (millions)	1,396.80	Payout Ratio	0.69
Short Ratio	4.13	Change in Payout Ratio	-0.05
Last Split Date	04/27/1993	Last Dividend Payout / Amount	03/27/2009 / $0.47

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.42	Current (1=Strong Buy, 5=Strong Sell)	3.40
Current Year EPS Consensus Estimate	2.55	30 Days Ago	3.40
Estimated Long-Term EPS Growth Rate	5.90	60 Days Ago	3.40
Next EPS Report Date	08/10/2009	90 Days Ago	3.40

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.12	vs. Previous Year	5.49%	vs. Previous Year	-30.39%
Trailing 12 Months:	11.53	vs. Previous Quarter	-8.57%	vs. Previous Quarter:	6.73%
PEG Ratio	2.05				

Price Ratios		ROE		ROA	
Price/Book	1.39	03/31/09	12.46	03/31/09	2.67

Price/Cash Flow	4.51	12/31/08	12.31	12/31/08	2.62
Price / Sales	0.42	09/30/08	13.19	09/30/08	2.87
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	0.78	03/31/09	0.77	03/31/09	3.70
12/31/08	0.80	12/31/08	0.68	12/31/08	3.16
09/30/08	0.76	09/30/08	0.56	09/30/08	3.48
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	5.21	03/31/09	5.21	03/31/09	22.16
12/31/08	4.34	12/31/08	4.34	12/31/08	21.53
09/30/08	4.80	09/30/08	4.80	09/30/08	21.15
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	15.05	03/31/09	0.45	03/31/09	30.91
12/31/08	18.16	12/31/08	0.46	12/31/08	31.52
09/30/08	23.38	09/30/08	0.47	09/30/08	31.92

Zacks.com Quotes and Research

NORTHWEST NAT GAS CO (NYSE)

Scottrade

NWN	39.90	-0.13	(-0.32%)	Vol. 173,466	16:03 ET

NW Natural is principally engaged in the distribution of natural gas.The Oregon Public Utility Commission (OPUC) has allocated to NW Natural as its exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the fertile Willamette Valley and the coastal area from Astoria to Coos Bay. NW Natural also holds certificates from the Washington Utilities and Transportation Commission (WUTC) granting it exclusive rights to serve portions of three Washington counties bordering the Columbia River.

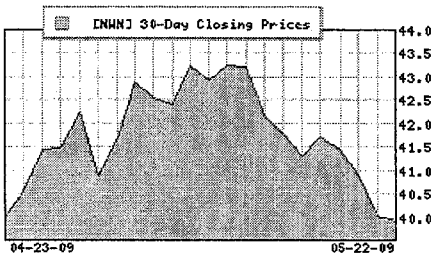
General Information

NORTHWEST NAT G
220 NW Second Avenue
Portland, OR 97209
Phone: 503 226-4211
Fax: 503 273-4824
Web: www.nwnatural.com
Email: Bob.Hess@nwnatural.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	07/17/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	40.03
52 Week High	55.44
52 Week Low	36.61
Beta	0.29
20 Day Moving Average	170,996.70
Target Price Consensus	51.25



% Price Change		% Price Change Relative to S&P 500	
4 Week	-0.23	4 Week	-4.17
12 Week	-3.20	12 Week	-17.84
YTD	-9.79	YTD	-4.47

Share Information		Dividend Information	
Shares Outstanding (millions)	26.50	Dividend Yield	3.96%
		Annual Dividend	$1.58
Market Capitalization (millions)	1,057.39	Payout Ratio	0.57
Short Ratio	7.62	Change in Payout Ratio	-0.05
Last Split Date	09/09/1996	Last Dividend Payout / Amount	04/28/2009 / $0.40

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.17	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	2.77	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	6.80	60 Days Ago	2.00
Next EPS Report Date	07/17/2009	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.39	vs. Previous Year	9.82%	vs. Previous Year	12.81%
Trailing 12 Months:	14.35	vs. Previous Quarter	43.20%	vs. Previous Quarter:	25.24%
PEG Ratio	2.13				

Price Ratios	ROE	ROA

Price/Book	1.59	03/31/09	11.69	03/31/09	3.37
Price/Cash Flow	7.44	12/31/08	11.18	12/31/08	3.31
Price / Sales	0.97	09/30/08	10.77	09/30/08	3.29
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.03	03/31/09	0.80	03/31/09	6.78
12/31/08	0.87	12/31/08	0.70	12/31/08	6.70
09/30/08	0.69	09/30/08	0.44	09/30/08	6.47
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	10.81	03/31/09	10.81	03/31/09	25.05
12/31/08	10.62	12/31/08	10.62	12/31/08	23.77
09/30/08	10.30	09/30/08	10.30	09/30/08	22.88
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	10.10	03/31/09	0.88	03/31/09	46.93
12/31/08	11.16	12/31/08	0.81	12/31/08	44.90
09/30/08	10.09	09/30/08	0.85	09/30/08	45.84

Zacks.com Quotes and Research

PIEDMONT NAT GAS INC (NYSE)

Scottrade

PNY	21.81	-0.28	(-1.27%)	Vol. 335,349	16:02 ET

Piedmont Natural Gas Co, Inc., is an energy and services company engaged in the transportation and sale of natural gas and the sale of propane to residential, commercial and industrial customers in North Carolina, South Carolina and Tennessee. The Company is the second-largest natural gas utility in the southeast. The Company and its non-utility subsidiaries and divisions are also engaged in acquiring, marketing and arranging for the transportation and storage of natural gas for large-volume purchasers, and in the sale of propane to customers in the Company's three-state service area.

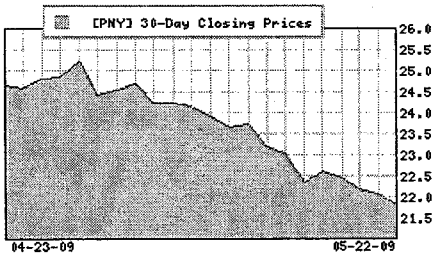
General Information

PIEDMONT NAT GA
4720 Piedmont Row Drive
Charlotte, NC 28210
Phone: 704 364-3120
Fax: 704-365-3849
Web: www.piedmontng.com
Email: investorrelations@piedmontng.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	October
Last Reported Quarter	04/30/09
Next EPS Date	06/08/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	22.09
52 Week High	35.29
52 Week Low	20.52
Beta	0.25
20 Day Moving Average	463,561.66
Target Price Consensus	28.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	-11.52	4 Week	-15.02
12 Week	-10.36	12 Week	-23.92
YTD	-31.13	YTD	-27.83

Share Information		Dividend Information	
Shares Outstanding (millions)	73.48	Dividend Yield	4.95%
		Annual Dividend	$1.08
Market Capitalization (millions)	1,602.69	Payout Ratio	0.00
Short Ratio	9.00	Change in Payout Ratio	0.00
Last Split Date	11/01/2004	Last Dividend Payout / Amount	03/23/2009 / $0.27

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.66	Current (1=Strong Buy, 5=Strong Sell)	2.67
Current Year EPS Consensus Estimate	1.53	30 Days Ago	2.67
Estimated Long-Term EPS Growth Rate	6.50	60 Days Ago	2.67
Next EPS Report Date	06/08/2009	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.22	vs. Previous Year	-1.79%	vs. Previous Year	-1.12%
Trailing 12 Months:	13.89	vs. Previous Quarter	-%	vs. Previous Quarter:	150.08%
PEG Ratio	2.19				

Price Ratios		ROE		ROA	
Price/Book	1.68	04/30/09	-	04/30/09	-
Price/Cash Flow	7.71	01/31/09	11.70	01/31/09	3.55
Price / Sales	-	10/31/08	11.95	10/31/08	3.67
Current Ratio		**Quick Ratio**		**Operating Margin**	
04/30/09	-	04/30/09	-	04/30/09	-
01/31/09	0.99	01/31/09	0.76	01/31/09	5.22
10/31/08	0.88	10/31/08	0.59	10/31/08	5.27
Net Margin		**Pre-Tax Margin**		**Book Value**	
04/30/09	-	04/30/09	-	04/30/09	-
01/31/09	8.66	01/31/09	8.66	01/31/09	12.98
10/31/08	8.78	10/31/08	8.78	10/31/08	12.11
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
04/30/09	-	04/30/09	-	04/30/09	-
01/31/09	10.50	01/31/09	0.83	01/31/09	45.46
10/31/08	11.18	10/31/08	0.90	10/31/08	47.24

Zacks.com Quotes and Research

SOUTH JERSEY INDS INC (NYSE)

Scottrade

SJI	33.20	-0.29	(-0.87%)	Vol. 177,091	16:03 ET

South Jersey Inds Inc. is engaged in the business of operating, through subsidiaries, various business enterprises. The company's most significant subsidiary is South Jersey Gas Company (SJG). SJG is a public utility company engaged in the purchase, transmission and sale of natural gas for residential, commercial and industrial use. SJG also makes off-system sales of natural gas on a wholesale basis to various customers on the interstate pipeline system and transports natural gas.

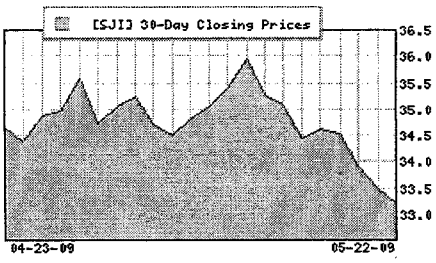
General Information

SOUTH JERSEY IN
1 South Jersey Plaza
Folsom, NJ 08037
Phone: 609 561-9000
Fax: 609 561-8225
Web: www.sjindustries.com
Email: investorrelations@sjindustries.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	08/06/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	33.49
52 Week High	40.78
52 Week Low	25.19
Beta	0.26
20 Day Moving Average	229,042.00
Target Price Consensus	41.4



% Price Change		% Price Change Relative to S&P 500	
4 Week	-4.16	4 Week	-7.95
12 Week	-6.14	12 Week	-20.33
YTD	-16.69	YTD	-11.56

Share Information		Dividend Information	
Shares Outstanding (millions)	29.74	Dividend Yield	3.58%
		Annual Dividend	$1.19
Market Capitalization (millions)	987.30	Payout Ratio	0.49
Short Ratio	5.48	Change in Payout Ratio	0.00
Last Split Date	07/01/2005	Last Dividend Payout / Amount	03/06/2009 / $0.30

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.27	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	2.43	30 Days Ago	2.50
Estimated Long-Term EPS Growth Rate	8.40	60 Days Ago	2.67
Next EPS Report Date	08/06/2009	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.64	vs. Previous Year	10.61%	vs. Previous Year	4.06%
Trailing 12 Months:	13.66	vs. Previous Quarter	117.91%	vs. Previous Quarter:	35.30%
PEG Ratio	1.62				

Price Ratios	ROE	ROA

Price/Book	1.82	03/31/09	14.14	03/31/09	4.30
Price/Cash Flow	9.55	12/31/08	13.56	12/31/08	4.16
Price / Sales	1.01	09/30/08	13.53	09/30/08	4.25
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	0.93	03/31/09	0.74	03/31/09	7.43
12/31/08	0.87	12/31/08	0.52	12/31/08	7.07
09/30/08	0.94	09/30/08	0.45	09/30/08	6.99
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	14.51	03/31/09	14.51	03/31/09	18.20
12/31/08	13.40	12/31/08	13.40	12/31/08	17.33
09/30/08	12.52	09/30/08	12.52	09/30/08	17.32
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	5.73	03/31/09	0.61	03/31/09	38.07
12/31/08	6.46	12/31/08	0.65	12/31/08	39.33
09/30/08	6.67	09/30/08	0.69	09/30/08	41.08

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

SOUTHWEST GAS CORP (NYSE)

Scottrade

SWX	19.68	▲0.09	(0.46%)	Vol. 320,937	16:02 ET

SOUTHWEST GAS CORP. is principally engaged in the business of purchasing,transporting, and distributing natural gas in portions of Arizona, Nevada,and California. The Company also engaged in financial services activities,through PriMerit Bank, Federal Savings Bank (PriMerit or the Bank), a wholly owned subsidiary.

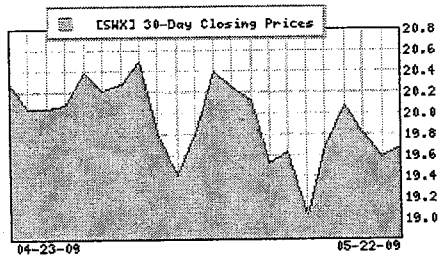
General Information

SOUTHWEST GAS
5241 Spring Mountain Road
P.O. Box 98510
Las Vegas, NV 89193-8510
Phone: 702 876-7237
Fax: 702-876-7037
Web: www.swgas.com
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	08/05/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	19.59
52 Week High	33.29
52 Week Low	17.08
Beta	0.69
20 Day Moving Average	419,823.44
Target Price Consensus	28



% Price Change		% Price Change Relative to S&P 500	
4 Week	-3.01	4 Week	-6.84
12 Week	-5.88	12 Week	-20.12
YTD	-21.97	YTD	-22.80

Share Information		Dividend Information	
Shares Outstanding (millions)	44.58	Dividend Yield	4.83%
		Annual Dividend	$0.95
Market Capitalization (millions)	877.30	Payout Ratio	0.65
Short Ratio	2.23	Change in Payout Ratio	0.12
Last Split Date	N/A	Last Dividend Payout / Amount	05/13/2009 / $0.24

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	-0.05	Current (1=Strong Buy, 5=Strong Sell)	2.60
Current Year EPS Consensus Estimate	1.84	30 Days Ago	2.60
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	2.60
Next EPS Report Date	08/05/2009	90 Days Ago	2.60

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	10.71	vs. Previous Year	-1.75%	vs. Previous Year	-15.21%
Trailing 12 Months:	14.16	vs. Previous Quarter	57.75%	vs. Previous Quarter:	35.42%
PEG Ratio	1.79				

Price Ratios		ROE		ROA	
Price/Book	0.81	03/31/09	5.45	03/31/09	1.56

Price/Cash Flow	3.34	12/31/08	5.93	12/31/08	1.69
Price / Sales	0.43	09/30/08	7.18	09/30/08	2.04
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	0.82	03/31/09	0.82	03/31/09	2.81
12/31/08	0.86	12/31/08	0.86	12/31/08	2.84
09/30/08	0.75	09/30/08	0.75	09/30/08	3.32
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	5.09	03/31/09	5.09	03/31/09	24.40
12/31/08	4.75	12/31/08	4.75	12/31/08	23.63
09/30/08	5.37	09/30/08	5.37	09/30/08	23.22
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	-	03/31/09	1.05	03/31/09	51.33
12/31/08	-	12/31/08	1.24	12/31/08	55.33
09/30/08	-	09/30/08	1.20	09/30/08	52.20

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WGL HLDGS INC (NYSE)

Scottrade

WGL	28.83	▼-0.25	(-0.86%)	Vol. 294,657	16:02 ET

WASHINGTON GAS LIGHT CO is a public utility that delivers and sells natural gas to metropolitan Washington, D.C. and adjoining areas in Maryland and Virginia. A distribution subsidiary serves portions of Virginia and West Virginia. The Company has four wholly-owned active subsidiaries that include: Shenandoah Gas Company (Shenandoah) is engaged in the delivery and sale of natural gas at retail in the Shenandoah Valley, including Winchester, Middletown, Strasburg, Stephens City and New Market, Virginia, and Martinsburg, West Virginia.

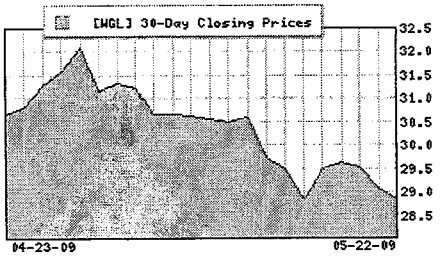
General Information

WGL HLDGS INC
101 Constitution Avenue NW
Washington, DC 20080
Phone: 703 750-2000
Fax: 703 750-4828
Web: www.wglholdings.com
Email: madams@washgas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	08/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	29.08
52 Week High	37.08
52 Week Low	22.40
Beta	0.24
20 Day Moving Average	463,851.84
Target Price Consensus	34.67



% Price Change		% Price Change Relative to S&P 500	
4 Week	-6.00	4 Week	-9.72
12 Week	-5.26	12 Week	-19.59
YTD	-11.81	YTD	-9.80

Share Information		Dividend Information	
Shares Outstanding (millions)	50.12	Dividend Yield	5.10%
		Annual Dividend	$1.47
Market Capitalization (millions)	1,445.07	Payout Ratio	0.56
Short Ratio	6.94	Change in Payout Ratio	-0.11
Last Split Date	05/02/1995	Last Dividend Payout / Amount	04/07/2009 / $0.37

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.03	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	2.45	30 Days Ago	2.50
Estimated Long-Term EPS Growth Rate	6.70	60 Days Ago	2.50
Next EPS Report Date	08/10/2009	90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.79	vs. Previous Year	-0.60%	vs. Previous Year	2.04%
Trailing 12 Months:	11.44	vs. Previous Quarter	60.19%	vs. Previous Quarter:	26.71%
PEG Ratio	1.77				

Price Ratios	ROE	ROA

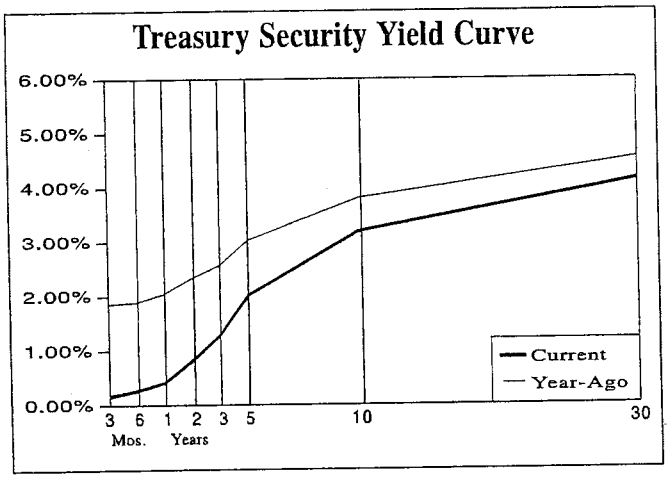
Price/Book	1.26	03/31/09	11.60	03/31/09	3.75
Price/Cash Flow	6.69	12/31/08	11.76	12/31/08	3.79
Price / Sales	0.58	09/30/08	11.60	09/30/08	3.72
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.20	03/31/09	1.04	03/31/09	5.08
12/31/08	1.06	12/31/08	0.70	12/31/08	5.11
09/30/08	0.99	09/30/08	0.42	09/30/08	5.09
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	7.58	03/31/09	7.58	03/31/09	22.89
12/31/08	8.04	12/31/08	8.04	12/31/08	21.79
09/30/08	7.08	09/30/08	7.08	09/30/08	20.99
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	8.22	03/31/09	0.57	03/31/09	35.81
12/31/08	7.91	12/31/08	0.60	12/31/08	37.05
09/30/08	8.11	09/30/08	0.58	09/30/08	35.95

ATTACHMENT D

Selected Yields

	Recent (5/20/09)	3 Months Ago (2/18/09)	Year Ago (5/21/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.26	0.52	2.55
3-month LIBOR	0.72	1.25	2.64
Bank CDs			
6-month	0.72	0.87	1.77
1-year	0.97	1.20	2.05
5-year	1.92	2.14	3.17
U.S. Treasury Securities			
3-month	0.17	0.30	1.86
6-month	0.27	0.48	1.89
1-year	0.42	0.63	2.05
5-year	2.03	1.80	3.04
10-year	3.19	2.76	3.81
10-year (inflation-protected)	1.51	1.61	1.16
30-year	4.14	3.55	4.54
30-year Zero	4.26	3.43	4.64

	Recent (5/20/09)	3 Months Ago (2/18/09)	Year Ago (5/21/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.02	4.05	4.98
FHLMC 6.5% (Gold)	2.27	3.92	5.11
FNMA 6.5%	2.03	3.78	4.89
FNMA ARM	2.78	3.90	4.41
Corporate Bonds			
Financial (10-year) A	6.66	8.33	5.54
Industrial (25/30-year) A	6.21	6.14	6.03
Utility (25/30-year) A	6.01	5.74	6.04
Utility (25/30-year) Baa/BBB	7.59	7.07	6.36
Foreign Bonds (10-Year)			
Canada	3.14	2.86	3.58
Germany	3.43	2.99	4.27
Japan	1.43	1.26	1.62
United Kingdom	3.58	3.39	4.88
Preferred Stocks			
Utility A	6.09	6.03	6.31
Financial A	8.37	13.57	6.73
Financial Adjustable A	5.52	5.52	5.52



	Recent (5/20/09)	3 Months Ago (2/18/09)	Year Ago (5/21/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.61	4.89	4.53
25-Bond Index (Revs)	5.53	5.67	4.98
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.55	1.80
1-year A	1.16	0.65	1.90
5-year Aaa	1.82	1.85	2.92
5-year A	3.25	2.15	3.02
10-year Aaa	2.81	2.90	3.56
10-year A	4.35	3.40	3.76
25/30-year Aaa	4.40	4.72	4.45
25/30-year A	5.92	5.72	4.65
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.97	5.80	4.75
Electric AA	6.02	5.90	4.80
Housing AA	6.32	6.15	5.00
Hospital AA	6.27	6.10	5.05
Toll Road Aaa	6.07	5.95	4.80

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Seasonally Adjusted)

	Recent Levels 5/6/09	4/22/09	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	777464	862393	-84929	731759	706418	385094
Borrowed Reserves	507911	565360	-57449	579211	611473	433308
Net Free/Borrowed Reserves	269553	297033	-27480	152548	94946	-48213

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 5/4/09	4/27/09	Change	Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1608.2	1576.7	31.5	10.0%	11.2%	16.6%
M2 (M1+savings+small time deposits)	8303.9	8285.0	18.9	4.2%	10.4%	9.1%

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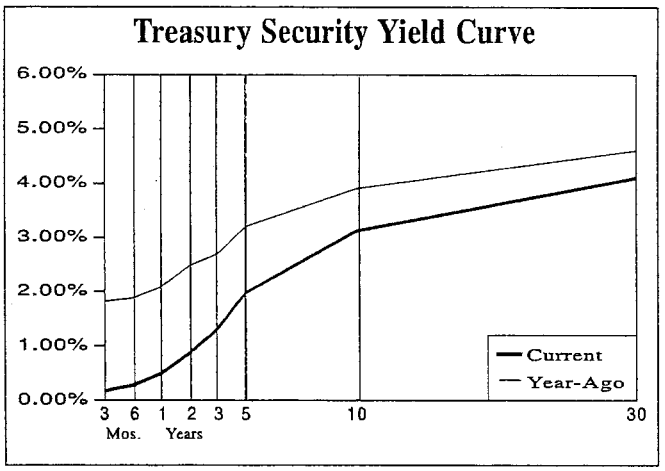
Selected Yields

	Recent (5/13/09)	3 Months Ago (2/11/09)	Year Ago (5/14/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.32	0.48	2.70
3-month LIBOR	0.88	1.23	2.72
Bank CDs			
6-month	0.73	0.89	1.77
1-year	0.98	1.08	2.05
5-year	1.93	2.37	3.16
U.S. Treasury Securities			
3-month	0.17	0.30	1.82
6-month	0.28	0.45	1.88
1-year	0.50	0.60	2.08
5-year	1.98	1.75	3.20
10-year	3.12	2.75	3.91
10-year (inflation-protected)	1.64	1.60	1.35
30-year	4.10	3.44	4.61
30-year Zero	4.18	3.31	4.71

	Recent (5/13/09)	3 Months Ago (2/11/09)	Year Ago (5/14/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.09	4.02	5.04
FHLMC 6.5% (Gold)	2.38	3.62	5.16
FNMA 6.5%	2.20	3.63	4.90
FNMA ARM	2.78	3.89	4.41
Corporate Bonds			
Financial (10-year) A	6.94	8.09	5.68
Industrial (25/30-year) A	6.19	5.94	6.06
Utility (25/30-year) A	6.01	5.60	6.10
Utility (25/30-year) Baa/BBB	7.57	7.00	6.41
Foreign Bonds (10-Year)			
Canada	3.10	2.94	3.60
Germany	3.34	3.19	4.17
Japan	1.46	1.31	1.68
United Kingdom	3.52	3.61	4.82
Preferred Stocks			
Utility A	6.35	6.01	6.28
Financial A	8.65	11.01	6.75
Financial Adjustable A	5.51	5.51	5.51



	Recent (5/13/09)	3 Months Ago (2/11/09)	Year Ago (5/14/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.63	4.96	4.62
25-Bond Index (Revs)	5.57	5.74	5.07
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.55	1.83
1-year A	1.16	0.65	1.93
5-year Aaa	1.82	1.76	2.97
5-year A	3.24	2.02	3.07
10-year Aaa	2.86	2.84	3.62
10-year A	4.41	3.34	3.83
25/30-year Aaa	4.43	4.71	4.55
25/30-year A	5.91	5.75	4.75
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.96	5.75	4.80
Electric AA	6.06	5.80	4.85
Housing AA	6.36	6.10	5.00
Hospital AA	6.31	6.15	5.05
Toll Road Aaa	6.11	5.85	4.85

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/6/09	4/22/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	777464	862387	-84923	731758	706418	385094
Borrowed Reserves	507911	565360	-57449	579211	611473	433308
Net Free/Borrowed Reserves	269553	297027	-27474	152547	94945	-48214

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/27/09	4/20/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1576.9	1559.4	17.5	7.3%	12.8%	14.2%
M2 (M1+savings+small time deposits)	8285.2	8243.6	41.6	1.9%	9.5%	8.8%

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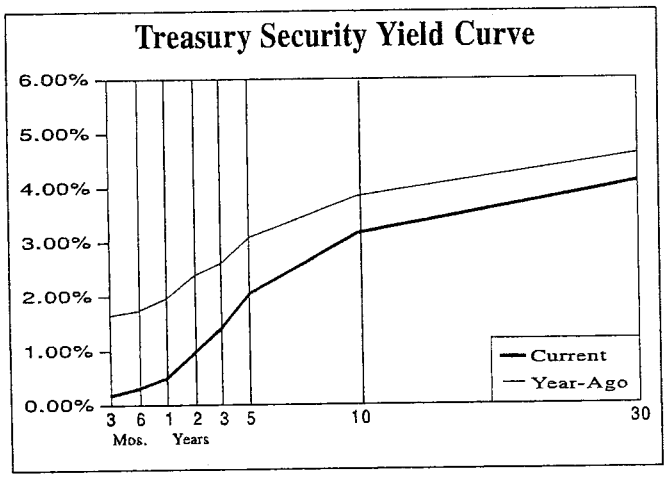
Selected Yields

	Recent (5/06/09)	3 Months Ago (2/04/09)	Year Ago (5/07/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.40	0.55	2.56
3-month LIBOR	0.97	1.24	2.73
Bank CDs			
6-month	0.79	0.87	1.72
1-year	0.98	1.29	1.99
5-year	1.93	2.41	3.05
U.S. Treasury Securities			
3-month	0.18	0.29	1.66
6-month	0.31	0.40	1.74
1-year	0.50	0.49	1.96
5-year	2.05	1.94	3.08
10-year	3.16	2.94	3.85
10-year (inflation-protected)	1.69	1.78	1.37
30-year	4.10	3.68	4.61
30-year Zero	4.14	3.55	4.68

	Recent (5/06/09)	3 Months Ago (2/04/09)	Year Ago (5/07/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.37	4.28	4.86
FHLMC 6.5% (Gold)	2.91	4.17	5.10
FNMA 6.5%	2.71	4.14	4.84
FNMA ARM	2.78	3.89	4.40
Corporate Bonds			
Financial (10-year) A	7.19	8.03	5.74
Industrial (25/30-year) A	6.31	6.15	6.03
Utility (25/30-year) A	6.10	6.00	6.11
Utility (25/30-year) Baa/BBB	7.54	7.27	6.39
Foreign Bonds (10-Year)			
Canada	3.07	3.12	3.67
Germany	3.24	3.36	4.18
Japan	1.41	1.36	1.67
United Kingdom	3.61	3.77	4.71
Preferred Stocks			
Utility A	6.00	6.02	6.24
Financial A	8.19	10.79	6.73
Financial Adjustable A	5.51	5.51	5.51



	Recent (5/06/09)	3 Months Ago (2/04/09)	Year Ago (5/07/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.70	5.16	4.63
25-Bond Index (Revs)	5.57	5.89	5.07
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.55	1.83
1-year A	1.16	0.65	1.93
5-year Aaa	1.84	1.79	3.03
5-year A	3.25	2.09	3.13
10-year Aaa	2.91	2.90	3.70
10-year A	4.45	3.40	3.90
25/30-year Aaa	4.53	4.82	4.62
25/30-year A	6.05	5.82	4.82
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.10	5.90	4.90
Electric AA	6.15	6.00	4.95
Housing AA	6.45	6.25	5.05
Hospital AA	6.40	6.20	5.10
Toll Road Aaa	6.20	6.05	4.95

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 4/22/09	4/8/09	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	862387	804790	57597	733984	671007	356363
Borrowed Reserves	565360	595938	-30578	587381	624561	419423
Net Free/Borrowed Reserves	297027	208852	88175	146604	46446	-63060

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 4/20/09	4/13/09	Change	Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1559.4	1576.3	-16.9	2.3%	13.7%	13.1%
M2 (M1+savings+small time deposits)	8244.9	8249.3	-4.4	1.0%	7.9%	8.1%

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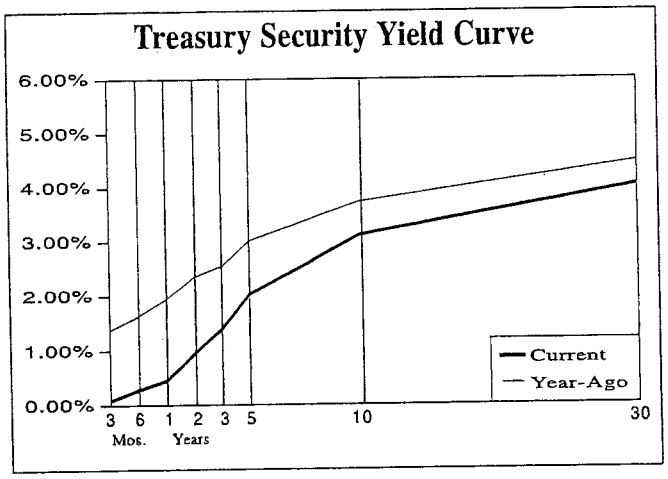
Selected Yields

	Recent (4/29/09)	3 Months Ago (1/28/09)	Year Ago (4/30/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.40	0.45	2.60
3-month LIBOR	1.03	1.17	2.85
Bank CDs			
6-month	0.79	0.88	1.75
1-year	0.98	1.25	1.77
5-year	1.93	2.39	2.96
U.S. Treasury Securities			
3-month	0.09	0.18	1.38
6-month	0.28	0.33	1.62
1-year	0.46	0.47	1.94
5-year	2.03	1.69	3.01
10-year	3.11	2.67	3.73
10-year (inflation-protected)	1.57	1.78	1.35
30-year	4.03	3.42	4.47
30-year Zero	4.05	3.29	4.54

	Recent (4/29/09)	3 Months Ago (1/28/09)	Year Ago (4/30/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.30	3.90	5.02
FHLMC 6.5% (Gold)	2.61	3.50	5.21
FNMA 6.5%	2.45	3.50	4.93
FNMA ARM	3.15	4.27	4.40
Corporate Bonds			
Financial (10-year) A	7.84	7.96	5.91
Industrial (25/30-year) A	6.41	6.18	6.00
Utility (25/30-year) A	6.33	6.10	6.12
Utility (25/30-year) Baa/BBB	7.58	7.04	6.31
Foreign Bonds (10-Year)			
Canada	3.08	2.96	3.59
Germany	3.13	3.23	4.12
Japan	1.42	1.27	1.59
United Kingdom	3.46	3.64	4.67
Preferred Stocks			
Utility A	7.53	5.98	6.19
Financial A	8.96	8.89	6.65
Financial Adjustable A	5.50	5.50	5.50



	Recent (4/29/09)	3 Months Ago (1/28/09)	Year Ago (4/30/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.57	5.13	4.68
25-Bond Index (Revs)	5.49	5.82	5.01
General Obligation Bonds (GOs)			
1-year Aaa	0.54	0.55	1.80
1-year A	1.04	0.65	1.90
5-year Aaa	1.80	1.84	3.00
5-year A	2.23	2.14	3.10
10-year Aaa	3.19	3.00	3.69
10-year A	3.55	3.50	3.90
25/30-year Aaa	4.67	5.05	4.61
25/30-year A	5.11	6.05	4.81
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.80	6.05	4.90
Electric AA	5.90	6.10	4.95
Housing AA	6.20	6.40	5.05
Hospital AA	6.15	6.45	5.10
Toll Road Aaa	5.95	6.15	4.95

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 4/22/09	4/8/09	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	862392	804794	57598	733986	671008	356363
Borrowed Reserves	565360	595938	-30578	587381	624561	419423
Net Free/Borrowed Reserves	297032	208856	88176	146606	46447	-63060

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 4/13/09	4/6/09	Change	Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1576.3	1644.4	-68.1	-6.3%	15.4%	14.8%
M2 (M1+savings+small time deposits)	8249.3	8247.7	1.6	3.0%	9.3%	8.3%

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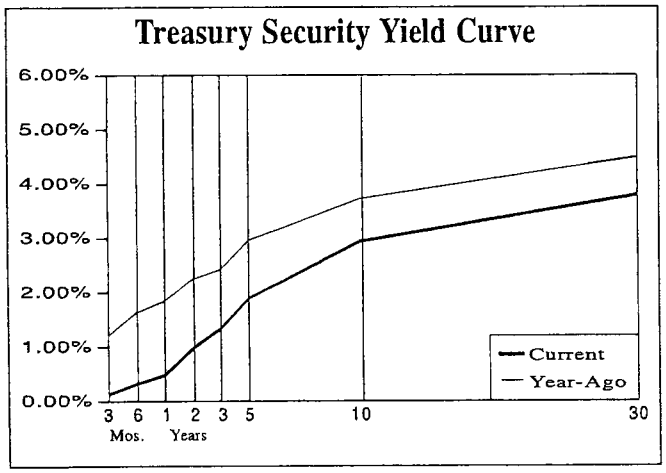
Selected Yields

	Recent (4/22/09)	3 Months Ago (1/21/09)	Year Ago (4/23/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.37	0.55	2.78
3-month LIBOR	1.10	1.13	2.92
Bank CDs			
6-month	0.80	1.03	1.75
1-year	0.99	1.34	1.78
5-year	1.93	2.38	2.95
U.S. Treasury Securities			
3-month	0.13	0.11	1.21
6-month	0.32	0.29	1.63
1-year	0.48	0.43	1.84
5-year	1.89	1.61	2.96
10-year	2.94	2.54	3.73
10-year (inflation-protected)	1.59	1.95	1.29
30-year	3.80	3.16	4.49
30-year Zero	3.79	2.94	4.60

	Recent (4/22/09)	3 Months Ago (1/21/09)	Year Ago (4/23/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.32	3.78	5.11
FHLMC 6.5% (Gold)	2.72	3.53	5.12
FNMA 6.5%	2.58	3.47	4.94
FNMA ARM	3.15	4.25	4.67
Corporate Bonds			
Financial (10-year) A	7.71	7.97	6.03
Industrial (25/30-year) A	6.31	6.05	6.10
Utility (25/30-year) A	6.19	6.03	6.15
Utility (25/30-year) Baa/BBB	7.41	6.66	6.27
Foreign Bonds (10-Year)			
Canada	2.94	2.73	3.67
Germany	3.21	3.00	4.15
Japan	1.44	1.23	1.46
United Kingdom	3.45	3.44	4.67
Preferred Stocks			
Utility A	6.31	6.05	6.03
Financial A	8.98	8.58	6.79
Financial Adjustable A	5.50	5.49	5.50



	Recent (4/22/09)	3 Months Ago (1/21/09)	Year Ago (4/23/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.78	4.80	4.61
25-Bond Index (Revs)	5.63	5.72	5.04
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.48	1.55
1-year A	1.16	0.58	1.65
5-year Aaa	1.73	1.71	2.85
5-year A	3.15	2.00	2.95
10-year Aaa	2.88	2.82	3.54
10-year A	4.43	3.32	3.75
25/30-year Aaa	4.44	4.76	4.53
25/30-year A	5.95	5.76	4.73
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.00	5.80	4.80
Electric AA	6.10	5.90	4.85
Housing AA	6.40	6.15	4.95
Hospital AA	6.35	6.10	5.00
Toll Road Aaa	6.15	5.95	4.85

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/8/09	3/25/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	804800	771271	33529	731287	619127	324505
Borrowed Reserves	595938	604849	-8911	586952	622967	403815
Net Free/Borrowed Reserves	208862	166422	42440	144335	-3841	-79310

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/6/09	3/30/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1641.2	1551.3	89.9	1.0%	26.6%	20.5%
M2 (M1+savings+small time deposits)	8244.7	8308.2	-63.5	3.3%	10.4%	8.2%

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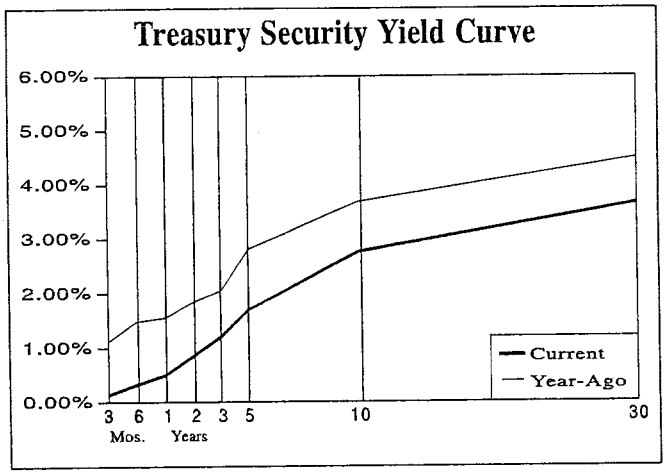
Selected Yields

	Recent (4/15/09)	3 Months Ago (1/14/09)	Year Ago (4/16/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.38	0.49	2.56
3-month LIBOR	1.11	1.08	2.73
Bank CDs			
6-month	0.81	1.03	1.76
1-year	1.02	1.34	1.79
5-year	2.01	2.38	2.87
U.S. Treasury Securities			
3-month	0.14	0.09	1.12
6-month	0.33	0.27	1.49
1-year	0.51	0.41	1.56
5-year	1.70	1.35	2.81
10-year	2.76	2.20	3.69
10-year (inflation-protected)	1.43	1.73	1.21
30-year	3.66	2.89	4.49
30-year Zero	3.66	2.75	4.62



	Recent (4/15/09)	3 Months Ago (1/14/09)	Year Ago (4/16/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.39	3.93	4.90
FHLMC 6.5% (Gold)	2.67	3.25	5.14
FNMA 6.5%	2.62	3.30	4.81
FNMA ARM	3.15	4.26	4.66
Corporate Bonds			
Financial (10-year) A	7.61	7.15	6.11
Industrial (25/30-year) A	6.25	5.84	6.12
Utility (25/30-year) A	6.17	5.88	6.28
Utility (25/30-year) Baa/BBB	7.59	6.60	6.40
Foreign Bonds (10-Year)			
Canada	2.94	2.56	3.68
Germany	3.14	2.93	4.04
Japan	1.44	1.27	1.35
United Kingdom	3.26	3.12	4.53
Preferred Stocks			
Utility A	6.36	6.05	6.06
Financial A	7.55	7.76	6.71
Financial Adjustable A	5.49	5.49	5.49
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.92	5.02	4.61
25-Bond Index (Revs)	5.74	5.90	5.04
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.48	1.55
1-year A	0.53	0.58	1.65
5-year Aaa	1.91	1.76	2.85
5-year A	2.13	2.06	2.95
10-year Aaa	3.09	2.82	3.54
10-year A	3.62	3.32	3.75
25/30-year Aaa	4.71	4.75	4.53
25/30-year A	5.75	5.75	4.73
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.70	5.75	4.80
Electric AA	5.80	5.80	4.85
Housing AA	6.10	6.10	4.95
Hospital AA	6.15	6.15	5.00
Toll Road Aaa	5.85	5.85	4.85

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/8/09	3/25/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	804805	771269	33536	731288	619127	324505
Borrowed Reserves	595938	604849	-8911	586952	622967	403815
Net Free/Borrowed Reserves	208867	166420	42447	144336	-3840	-79310

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/30/09	3/23/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1551.1	1549.4	1.7	-10.7%	8.2%	13.1%
M2 (M1+savings+small time deposits)	8308.0	8336.5	-28.5	7.3%	10.8%	9.1%

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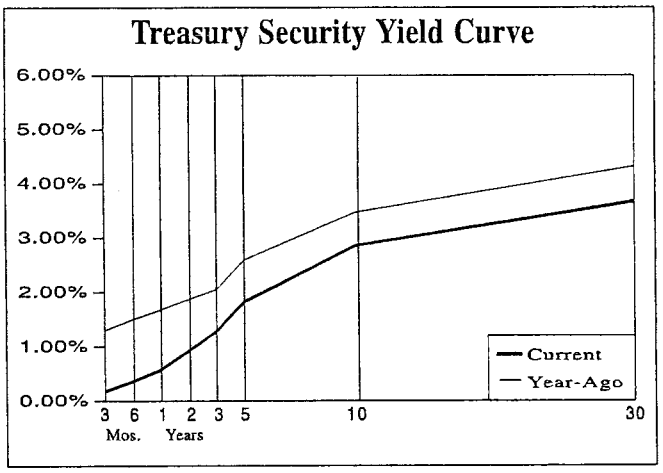
Selected Yields

	Recent (4/08/09)	3 Months Ago (1/07/09)	Year Ago (4/09/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.33	0.65	2.63
3-month LIBOR	1.14	1.40	2.72
Bank CDs			
6-month	0.83	1.10	1.76
1-year	1.04	1.41	1.79
5-year	2.05	2.38	2.87
U.S. Treasury Securities			
3-month	0.18	0.09	1.30
6-month	0.37	0.28	1.50
1-year	0.58	0.41	1.68
5-year	1.83	1.66	2.60
10-year	2.86	2.49	3.48
10-year (inflation-protected)	1.53	2.44	1.07
30-year	3.67	3.04	4.32
30-year Zero	3.67	2.87	4.43

	Recent (4/08/09)	3 Months Ago (1/07/09)	Year Ago (4/09/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.40	4.30	4.52
FHLMC 6.5% (Gold)	2.79	3.95	4.89
FNMA 6.5%	2.79	3.75	4.58
FNMA ARM	3.15	4.26	4.67
Corporate Bonds			
Financial (10-year) A	7.85	7.56	6.06
Industrial (25/30-year) A	6.27	6.26	5.93
Utility (25/30-year) A	6.20	6.07	6.14
Utility (25/30-year) Baa/BBB	7.63	6.72	6.28
Foreign Bonds (10-Year)			
Canada	2.90	2.93	3.56
Germany	3.21	3.20	4.01
Japan	1.46	1.26	1.35
United Kingdom	3.35	3.29	4.51
Preferred Stocks			
Utility A	6.35	6.11	6.06
Financial A	7.80	7.28	6.60
Financial Adjustable A	5.48	5.48	5.48



	Recent (4/08/09)	3 Months Ago (1/07/09)	Year Ago (4/09/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.95	5.24	4.90
25-Bond Index (Revs)	5.75	6.00	5.18
General Obligation Bonds (GOs)			
1-year Aaa	0.47	0.85	1.55
1-year A	1.20	0.95	1.70
5-year Aaa	2.03	2.48	2.94
5-year A	3.45	2.77	3.05
10-year Aaa	3.20	3.53	3.70
10-year A	4.75	4.03	3.90
25/30-year Aaa	4.77	5.04	4.78
25/30-year A	6.25	6.04	4.98
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.30	6.10	5.05
Electric AA	6.40	6.25	5.05
Housing AA	6.70	6.55	5.35
Hospital AA	6.65	6.50	5.30
Toll Road Aaa	6.45	6.25	5.10

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	3/25/09	3/11/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	771276	621568	149708	730382	566553	294869
Borrowed Reserves	604849	630177	-25328	591508	599533	385679
Net Free/Borrowed Reserves	166427	-8609	175036	138874	-32980	-90810

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/23/09	3/16/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1551.1	1564.0	-12.9	-11.2%	10.8%	13.3%
M2 (M1+savings+small time deposits)	8372.3	8375.2	-2.9	10.1%	12.8%	9.9%

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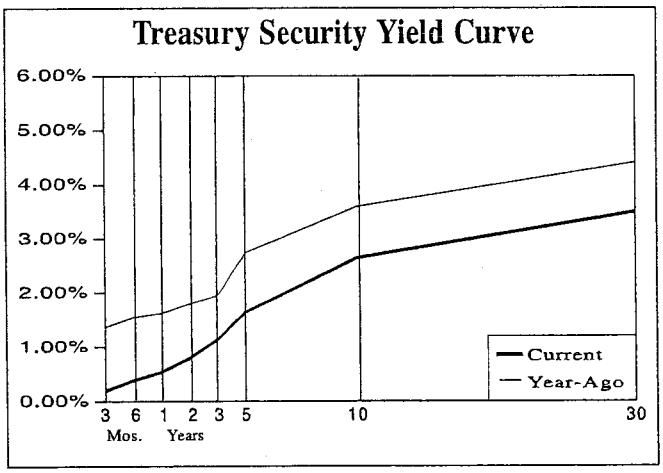
Selected Yields

	Recent (4/01/09)	3 Months Ago (12/30/08)	Year Ago (4/02/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.44	0.06	2.67
3-month LIBOR	1.18	1.44	2.70
Bank CDs			
6-month	0.83	1.16	1.78
1-year	1.04	1.43	1.76
5-year	2.06	2.51	2.87
U.S. Treasury Securities			
3-month	0.20	0.09	1.37
6-month	0.39	0.24	1.55
1-year	0.54	0.31	1.62
5-year	1.64	1.44	2.74
10-year	2.65	2.05	3.60
10-year (inflation-protected)	1.32	2.33	1.12
30-year	3.50	2.56	4.41
30-year Zero	3.52	2.42	4.48

	Recent (4/01/09)	3 Months Ago (12/30/08)	Year Ago (4/02/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.53	4.11	4.81
FHLMC 6.5% (Gold)	3.12	4.03	5.05
FNMA 6.5%	3.04	3.89	4.79
FNMA ARM	3.15	4.22	4.67
Corporate Bonds			
Financial (10-year) A	7.49	7.08	6.30
Industrial (25/30-year) A	6.17	5.90	6.07
Utility (25/30-year) A	5.99	5.85	6.16
Utility (25/30-year) Baa/BBB	7.41	6.58	6.25
Foreign Bonds (10-Year)			
Canada	2.78	2.66	3.63
Germany	2.99	2.95	3.99
Japan	1.35	1.17	1.37
United Kingdom	3.13	3.09	4.43
Preferred Stocks			
Utility A	6.74	6.00	6.16
Financial A	9.90	7.89	6.74
Financial Adjustable A	5.48	5.48	5.48



	Recent (4/01/09)	3 Months Ago (12/30/08)	Year Ago (4/02/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	5.00	5.46	4.96
25-Bond Index (Revs)	5.78	6.22	5.24
General Obligation Bonds (GOs)			
1-year Aaa	0.50	0.85	1.60
1-year A	0.60	0.95	1.70
5-year Aaa	2.08	2.57	3.00
5-year A	2.33	2.87	3.10
10-year Aaa	3.20	3.70	3.79
10-year A	3.73	4.20	4.00
25/30-year Aaa	4.79	5.17	4.91
25/30-year A	5.83	6.15	5.11
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.80	6.15	5.20
Electric AA	5.85	6.20	5.25
Housing AA	6.15	6.50	5.35
Hospital AA	6.20	6.55	5.40
Toll Road Aaa	5.90	6.25	5.25

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	3/25/09	3/11/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	771194	621518	149676	730364	566544	294864
Borrowed Reserves	604849	630177	-25328	591508	599533	385679
Net Free/Borrowed Reserves	166345	-8659	175004	138856	-32990	-90815

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/16/09	3/9/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1565.6	1577.1	-11.5	-8.4%	19.8%	14.4%
M2 (M1+savings+small time deposits)	8376.2	8342.9	33.3	12.1%	18.2%	10.2%

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ARIZONA WATER COMPANY
DOCKET NO. W-01445A-08-0440
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ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
COST OF CAPITAL SUMMARY

DOCKET NO. W-01445A-08-0440
SCHEDULE WAR - 1, PAGE 1 OF 3

WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) CAPITAL RATIO	(C) COST RATE	(D) WEIGHTED COST RATE
1	Long-Term Debt	$ 75,000,000	50.76%	7.31%	3.71%
2	Common Equity	72,744,646	49.24%	8.33%	4.10%
3	Total Capitalization	$ 147,744,646	100.00%		
4	**WEIGHTED AVERAGE COST OF CAPITAL**				**7.81%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): TESTIMONY, WAR - SCHEDULE WAR-1, PAGE 2
COLUMN (C): COLUMN (A) x COLUMN (B)

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
COST OF CAPITAL SUMMARY

COST OF LONG-TERM DEBT

LINE NO.	LONG-TERM DEBT ISSUANCES	(A) AMOUNT OUTSTANDING	(B) ANNUAL COST	(C) INTEREST RATE
1	SERIES K BONDS, DUE APRIL 1, 2031	$ 15,000,000	$ 1,208,265	8.06%
2	SERIES L BONDS, DUE AUGUST 1, 2036	25,000,000	1,576,450	6.31%
3	SERIES M BONDS, DUE AUGUST 1, 2038	35,000,000	2,695,000	7.70%
4	TOTALS	$ 75,000,000	$ 5,479,715	7.31%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2, PAGE 2
COLUMN (B): COMPANY SCHEDULE D-2, PAGE 2
COLUMN (C): COLUMN (B) / COLUMN (A)

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
COST OF CAPITAL SUMMARY

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - WATER COMPANY SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.32%	SCHEDULE WAR-2, COLUMN (C), LINE 4
3	DCF - NATURAL GAS LDC SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	11.42%	SCHEDULE WAR-2, COLUMN (C), LINE 15
4	**AVERAGE OF DCF ESTIMATES**	**10.37%**	(LINE 2 + LINE 3) / 2
5	**CAPM METHODOLOGY**		
6	CAPM - WATER COMPANY GEOMETRIC MEAN ESTIMATE	6.04%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 4
7	CAPM - NATURAL GAS LDC GEOMETRIC MEAN ESTIMATE	5.26%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 15
8	CAPM - WATER COMPANY ARITHMETIC MEAN ESTIMATE	7.43%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 4
9	CAPM - NATURAL GAS LDC ARITHMETIC MEAN ESTIMATE	6.39%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 15
10	**AVERAGE OF CAPM ESTIMATES**	**6.28%**	(SUM OF LINES 6 THRU 9) / 4
11	**AVERAGE OF DCF AND CAPM ESTIMATES**	**8.33%**	(LINE 4 + LINE 10) / 2

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DCF COST OF EQUITY CAPITAL

DOCKET NO. W-01445A-08-0440
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	AWR	AMERICAN STATES WATER CO.	3.00%	+	7.81%	=	10.81%
2	CWT	CALIFORNIA WATER SERVICE GROUP	3.21%	+	6.63%	=	9.85%
3	WTR	AQUA AMERICA, INC.	3.02%	+	4.30%	=	7.31%
4	**WATER COMPANY AVERAGE**						**9.32%**
5	AGL	AGL RESOURCES, INC.	6.00%	+	5.59%	=	11.59%
6	ATO	ATMOS ENERGY CORP.	5.52%	+	11.03%	=	16.55%
7	LG	LACLEDE GROUP, INC.	4.54%	+	5.21%	=	9.75%
8	NJR	NEW JERSEY RESOURCES CORPORATION	3.83%	+	5.70%	=	9.53%
9	GAS	NICOR, INC.	5.76%	+	5.02%	=	10.79%
10	NWN	NORTHWEST NATURAL GAS CO.	3.79%	+	4.94%	=	8.73%
11	PNY	PIEDMONT NATURAL GAS COMPANY	4.32%	+	5.50%	=	9.82%
12	SJI	SOUTH JERSEY INDUSTIES, INC.	6.56%	+	7.89%	=	14.45%
13	SWX	SOUTHWEST GAS CORPORATION	4.71%	+	9.03%	=	13.75%
14	WGL	WGL HOLDINGS, INC.	4.72%	+	4.52%	=	9.24%
15	**NATURAL GAS LDC AVERAGE**						**11.42%**

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND YIELD CALCULATION

DOCKET NO. W-01445A-08-0440
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	/	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	AWR	AMERICAN STATES WATER CO.	$1.00	/	$33.28	=	3.00%
2	CWT	CALIFORNIA WATER SERVICE GROUP	1.18	/	36.74	=	3.21%
3	WTR	AQUA AMERICA, INC.	0.54	/	17.91	=	3.02%
4	**WATER COMPANY AVERAGE**						**3.08%**
5	AGL	AGL RESOURCES, INC.	$1.72	/	$28.65	=	6.00%
6	ATO	ATMOS ENERGY CORP.	1.32	/	23.93	=	5.52%
7	LG	LACLEDE GROUP, INC.	1.54	/	33.88	=	4.54%
8	NJR	NEW JERSEY RESOURCES CORPORATION	1.24	/	32.39	=	3.83%
9	GAS	NICOR, INC.	1.86	/	32.27	=	5.76%
10	NWN	NORTHWEST NATURAL GAS CO.	1.58	/	41.65	=	3.79%
11	PNY	PIEDMONT NATURAL GAS COMPANY	1.04	/	24.10	=	4.32%
12	SJI	SOUTH JERSEY INDUSTIES, INC.	2.27	/	34.64	=	6.56%
13	SWX	SOUTHWEST GAS CORPORATION	0.95	/	20.19	=	4.71%
14	WGL	WGL HOLDINGS, INC.	1.44	/	30.53	=	4.72%
15	**NATURAL GAS LDC AVERAGE**						**4.98%**

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 04/24/2009 (WATER COMPANIES) AND 03/13/2009 (NATURAL GAS LDC's).
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 04/06/2009 TO 05/29/2009 STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) / COLUMN (B)

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	AWR	AMERICAN STATES WATER CO.	6.00%	+	1.81%	=	7.81%
2	CWT	CALIFORNIA WATER SERVICE GROUP	6.00%	+	0.63%	=	6.63%
3	WTR	AQUA AMERICA, INC.	4.00%	+	0.30%	=	4.30%
4	**WATER COMPANY AVERAGE**						**6.25%**
5	AGL	AGL RESOURCES, INC.	5.30%	+	0.29%	=	5.59%
6	ATO	ATMOS ENERGY CORP.	4.05%	+	6.98%	=	11.03%
7	LG	LACLEDE GROUP, INC.	4.50%	+	0.71%	=	5.21%
8	NJR	NEW JERSEY RESOURCES CORPORATION	5.25%	+	0.45%	=	5.70%
9	GAS	NICOR, INC.	5.00%	+	0.02%	=	5.02%
10	NWN	NORTHWEST NATURAL GAS CO.	4.60%	+	0.34%	=	4.94%
11	PNY	PIEDMONT NATURAL GAS COMPANY	5.50%	+	0.00%	=	5.50%
12	SJI	SOUTH JERSEY INDUSTIES, INC.	7.00%	+	0.89%	=	7.89%
13	SWX	SOUTHWEST GAS CORPORATION	4.25%	+	4.78%	=	9.03%
14	WGL	WGL HOLDINGS, INC.	4.50%	+	0.02%	=	4.52%
15	**NATURAL GAS LDC AVERAGE**						**6.44%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. W-01445A-08-0440
SCHEDULE WAR - 4, PAGE 2 OF 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	{ [((M ÷ B) + 1) / 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	AWR	AMERICAN STATES WATER CO.	4.75%	x	{ [((1.76) + 1) / 2] - 1 }	=	1.81%
2	CWT	CALIFORNIA WATER SERVICE GROUP	1.50%	x	{ [((1.85) + 1) / 2] - 1 }	=	0.63%
3	WTR	AQUA AMERICA, INC.	0.50%	x	{ [((2.20) + 1) / 2] - 1 }	=	0.30%
4	**WATER COMPANY AVERAGE**						**0.91%**
5	AGL	AGL RESOURCES, INC.	1.75%	x	{ [((1.33) + 1) / 2] - 1 }	=	0.29%
6	ATO	ATMOS ENERGY CORP.	3.50%	x	{ [((0.99) + 1) / 2] + 1 }	=	6.98%
7	LG	LACLEDE GROUP, INC.	3.25%	x	{ [((1.44) + 1) / 2] - 1 }	=	0.71%
8	NJR	NEW JERSEY RESOURCES CORPORATION	1.25%	x	{ [((1.72) + 1) / 2] - 1 }	=	0.45%
9	GAS	NICOR, INC.	0.10%	x	{ [((1.45) + 1) / 2] - 1 }	=	0.02%
10	NWN	NORTHWEST NATURAL GAS CO.	1.00%	x	{ [((1.67) + 1) / 2] - 1 }	=	0.34%
11	PNY	PIEDMONT NATURAL GAS COMPANY	0.01%	x	{ [((1.91) + 1) / 2] - 1 }	=	0.00%
12	SJI	SOUTH JERSEY INDUSTIES, INC.	2.00%	x	{ [((1.89) + 1) / 2] - 1 }	=	0.89%
13	SWX	SOUTHWEST GAS CORPORATION	2.50%	x	{ [((0.83) + 1) / 2] + 1 }	=	4.78%
14	WGL	WGL HOLDINGS, INC.	0.10%	x	{ [((1.38) + 1) / 2] - 1 }	=	0.02%
15	**NATURAL GAS LDC AVERAGE**						**1.45%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 04/24/2009 (WATER COMPANIES) AND 03/13/2009 (NATURAL GAS LDC's)
COLUMN (C): COLUMN (A) x COLUMN (B)

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	WATER COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	AWR	AMERICAN STATES WATER CO.	2004	0.1524		6.60%		1.01%	15.01	16.75	
2			2005	0.3182		8.50%		2.70%	15.72	16.80	
3			2006	0.3158		8.10%		2.56%	16.64	17.05	
4			2007	0.4074		9.30%		3.79%	17.53	17.23	
5			2008	0.3548		8.60%		3.05%	17.95	17.30	
6			GROWTH 2004 - 2008					2.62%	5.00%		0.81%
7			2009	0.4111		9.50%		3.91%		18.25	5.49%
8			2010	0.4462		10.00%		4.46%		18.75	4.11%
9			2012-14	0.5077		12.50%		6.35%	3.00%	20.25	3.20%
10											
11	CWT	CALIFORNIA WATER SERVICE GROUP	2004	0.2260		9.00%		2.03%	15.66	18.37	
12			2005	0.2245		9.30%		2.09%	15.79	18.39	
13			2006	0.1418		6.80%		0.96%	18.15	20.66	
14			2007	0.2267		8.10%		1.84%	18.50	20.67	
15			2008	0.3842		9.90%		3.80%	19.44	20.72	
16			GROWTH 2004 - 2008					2.15%	6.50%		3.06%
17			2009	0.4244		10.50%		4.46%		21.00	1.35%
18			2010	0.4465		10.50%		4.69%		21.25	1.27%
19			2012-14	0.4943		12.00%		5.93%	3.00%	22.50	1.66%
20											
21	WTR	AQUA AMERICA, INC.	2004	0.4219		10.70%		4.51%	5.89	127.18	
22			2005	0.4366		11.20%		4.89%	6.30	128.97	
23			2006	0.3714		10.00%		3.71%	6.96	132.33	
24			2007	0.3239		9.70%		3.14%	7.32	133.40	
25			2008	0.3014		9.30%		2.80%	7.82	135.37	
26			GROWTH 2004 - 2008					3.81%	10.00%		1.57%
27			2009	0.3250		10.00%		3.25%		136.00	0.47%
28			2010	0.3778		10.50%		3.97%		136.50	0.42%
29			2012-14	0.5040		11.50%		5.80%	6.50%	138.00	0.39%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 04/24/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	NATURAL GAS LDC NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	AGL	AGL RESOURCES, INC.	2004	0.4956		11.00%		5.45%	18.06	76.70	
2			2005	0.4758		12.90%		6.14%	19.29	77.70	
3			2006	0.4559		13.20%		6.02%	20.71	77.70	
4			2007	0.3971		12.70%		5.04%	21.74	76.40	
5			2008	0.3801		12.60%		4.79%	21.48	76.90	
6			GROWTH 2004 - 2008					5.49%	11.50%		0.07%
7			2009	0.3630		12.50%		4.54%		78.00	1.43%
8			2010	0.3825		13.00%		4.97%		79.00	1.36%
9			2012-14	0.4125		14.50%		5.98%	0.50%	85.00	2.02%
10											
11	ATO	ATMOS ENERGY CORP.	2004	0.2278		7.60%		1.73%	18.05	62.80	
12			2005	0.2791		8.50%		2.37%	19.90	80.54	
13			2006	0.3700		9.80%		3.63%	20.16	81.74	
14			2007	0.3402		8.70%		2.96%	22.01	89.33	
15			2008	0.3500		8.80%		3.08%	22.60	90.81	
16			GROWTH 2004 - 2008					2.75%	7.50%		9.66%
17			2009	0.3714		9.00%		3.34%		92.00	1.31%
18			2010	0.3767		8.50%		3.20%		93.00	1.20%
19			2012-14	0.4400		9.50%		4.18%	4.00%	110.00	3.91%
20											
21	LG	LACLEDE GROUP, INC.	2004	0.2582		10.10%		2.61%	16.96	20.98	
22			2005	0.2789		10.90%		3.04%	17.31	21.17	
23			2006	0.4093		12.50%		5.12%	18.85	21.36	
24			2007	0.3723		11.60%		4.32%	19.79	21.65	
25			2008	0.4356		11.80%		5.14%	22.12	21.99	
26			GROWTH 2004 - 2008					4.04%	5.50%		1.18%
27			2009	0.4632		12.50%		5.79%		22.50	2.32%
28			2010	0.3962		10.50%		4.16%		23.00	2.27%
29			2012-14	0.4333		11.00%		4.77%	5.50%	26.00	3.41%
30											
31	NJR	NEW JERSEY RESOURCES CORPORATION	2004	0.4882		15.30%		7.47%	11.25	41.61	
32			2005	0.4859		17.00%		8.26%	10.60	41.32	
33			2006	0.4866		12.60%		6.13%	15.00	41.44	
34			2007	0.3484		10.10%		3.52%	15.50	41.61	
35			2008	0.5889		15.70%		9.25%	17.28	42.06	
36			GROWTH 2004 - 2008					6.93%	11.50%		0.27%
37			2009	0.5040		13.50%		6.80%		42.50	1.05%
38			2010	0.5259		13.00%		6.84%		43.00	1.11%
39			2012-14	0.5088		11.00%		5.60%	8.50%	45.00	1.36%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/13/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH COMPONENTS

DOCKET NO. W-01445A-08-0440
SCHEDULE WAR - 5, PAGE 3 OF 4

LINE NO.	STOCK SYMBOL	NATURAL GAS LDC NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	GAS	NICOR, INC.	2004	0.1622		13.10%		2.12%	16.99	44.10	
2			2005	0.1806		12.50%		2.26%	18.36	44.18	
3			2006	0.3519		14.70%		5.17%	19.43	44.90	
4			2007	0.3779		14.30%		5.40%	20.58	45.90	
5			2008	0.2928		12.30%		3.60%	21.55	45.13	
6			GROWTH 2004 - 2008					3.71%	4.00%		0.58%
7			2009	0.2560		11.00%		2.82%		45.00	-0.29%
8			2010	0.3586		12.50%		4.48%		45.00	-0.14%
9			2012-14	0.4364		12.00%		5.24%	4.50%	45.00	-0.06%
10											
11	NWN	NORTHWEST NATURAL GAS CO.	2004	0.3011		8.90%		2.68%	20.64	27.55	
12			2005	0.3744		9.90%		3.71%	21.28	27.58	
13			2006	0.4085		10.90%		4.45%	22.01	27.24	
14			2007	0.4783		12.50%		5.98%	22.52	26.41	
15			2008	0.4109		11.20%		4.60%	23.70	26.50	
16			GROWTH 2004 - 2008					4.28%	3.50%		-0.97%
17			2009	0.4255		11.00%		4.68%		26.50	0.00%
18			2010	0.4175		11.00%		4.59%		26.50	0.00%
19			2012-14	0.4203		11.00%		4.62%	3.50%	28.00	1.11%
20											
21	PNY	PIEDMONT NATURAL GAS COMPANY	2004	0.3307		11.10%		3.67%	11.15	76.67	
22			2005	0.3106		11.50%		3.57%	11.53	76.70	
23			2006	0.2578		11.00%		2.84%	11.83	74.61	
24			2007	0.2929		11.90%		3.49%	11.99	73.23	
25			2008	0.3087		12.40%		3.83%	12.11	73.26	
26			GROWTH 2004 - 2008					3.48%	6.00%		-1.13%
27			2009	0.3438		12.50%		4.30%		73.50	0.33%
28			2010	0.3889		13.50%		5.25%		73.50	0.16%
29			2012-14	0.4186		13.50%		5.65%	5.00%	73.00	-0.07%
30											
31	SJI	SOUTH JERSEY INDUSTIES, INC.	2004	0.4810		12.50%		6.01%	12.41	27.76	
32			2005	0.4971		12.40%		6.16%	13.50	28.98	
33			2006	0.6260		16.30%		10.20%	15.11	29.33	
34			2007	0.5167		12.80%		6.61%	16.25	29.61	
35			2008	0.5110		13.20%		6.75%	17.33	29.73	
36			GROWTH 2004 - 2008					6.01%	1241.00%		1.73%
37			2009	0.5102		13.50%		6.89%		30.50	2.59%
38			2010	0.5170		13.50%		6.98%		31.00	2.11%
39			2012-14	0.5161		14.50%		7.48%	4.50%	33.00	2.11%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/13/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	NATURAL GAS LDC NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	SWX	SOUTHWEST GAS CORPORATION	2004	0.5060		8.30%		4.20%	19.18	36.79	
2			2005	0.3440		6.40%		2.20%	19.10	39.33	
3			2006	0.5859		8.90%		5.21%	21.58	41.77	
4			2007	0.5590		8.50%		4.75%	22.98	42.81	
5			2008	0.3525		5.90%		2.08%	23.48	44.19	
6			GROWTH 2004 - 2008					3.69%	4.00%		4.69%
7			2009	0.3667		6.00%		2.20%		45.00	1.83%
8			2010	0.4595		7.50%		3.45%		46.00	2.03%
9			2012-14	0.5000		9.00%		4.50%	2.50%	50.00	2.50%
10											
11	WGL	WGL HOLDINGS, INC.	2004	0.3434		11.70%		4.02%	16.95	48.67	
12			2005	0.3803		11.70%		4.45%	17.80	48.65	
13			2006	0.3041		10.30%		3.13%	18.86	48.89	
14			2007	0.3476		10.40%		3.62%	19.83	49.45	
15			2008	0.4221		11.60%		4.90%	20.99	49.92	
16			GROWTH 2004 - 2008					4.02%	4.50%		0.64%
17			2009	0.4200		12.00%		5.04%		50.00	0.16%
18			2010	0.4118		11.50%		4.74%		50.00	0.08%
19			2012-14	0.4182		11.00%		4.60%	5.00%	50.00	0.03%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/13/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6 & 16, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6 & 16, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
GROWTH RATE COMPARISON

DOCKET NO. W-01445A-08-0440
SCHEDULE WAR - 6

WATER COMPANY SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) VALUE LINE PROJECTED DPS	(C) VALUE LINE PROJECTED BVPS	(D) VALUE LINE HISTORIC EPS	(D) VALUE LINE HISTORIC DPS	(D) VALUE LINE HISTORIC BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) 5 - YEAR COMPOUND HISTORY DPS	(F) 5 - YEAR COMPOUND HISTORY BVPS
1	AWR	7.81%	8.70%	9.50%	5.00%	3.00%	5.50%	2.00%	5.00%	5.53%	10.23%	2.96%	4.57%
2	CWT	6.63%	8.00%	4.75%	2.50%	3.50%	7.00%	0.50%	6.50%	4.68%	6.81%	0.87%	5.55%
3	WTR	4.30%	8.30%	10.00%	3.50%	6.50%	5.50%	8.00%	10.00%	7.40%	3.34%	8.35%	7.34%
4				8.08%	3.67%	4.33%	6.00%	3.50%	7.17%		6.79%	4.06%	5.82%
5	AVERAGES	6.25%	8.33%		5.36%			5.56%		5.87%		5.56%	

NATURAL GAS LDC SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) VALUE LINE PROJECTED DPS	(C) VALUE LINE PROJECTED BVPS	(D) VALUE LINE HISTORIC EPS	(D) VALUE LINE HISTORIC DPS	(D) VALUE LINE HISTORIC BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) 5 - YEAR COMPOUND HISTORY DPS	(F) 5 - YEAR COMPOUND HISTORY BVPS
1	AGL	5.59%	5.30%	3.00%	2.50%	0.50%	11.50%	6.50%	11.50%	5.83%	4.41%	9.94%	4.43%
2	ATO	11.03%	5.80%	4.00%	1.50%	4.00%	5.00%	1.50%	7.50%	4.19%	6.07%	1.60%	5.78%
3	LG	5.21%	6.50%	3.50%	2.50%	5.50%	9.50%	1.50%	5.50%	4.93%	9.74%	2.50%	6.87%
4	NJR	5.70%	8.00%	5.50%	5.50%	8.50%	7.50%	5.00%	11.50%	7.36%	12.26%	6.28%	11.33%
5	GAS	5.02%	5.90%	2.50%	-	4.50%	1.00%	0.50%	4.00%	3.07%	4.33%	0.00%	6.12%
6	NWN	4.94%	6.80%	7.00%	5.50%	3.50%	6.50%	2.00%	3.50%	4.97%	8.52%	3.99%	3.52%
7	PNY	5.50%	6.50%	7.50%	3.50%	5.00%	6.50%	4.50%	6.00%	5.64%	4.07%	4.92%	2.09%
8	SJI	7.89%	8.40%	5.50%	7.00%	4.50%	12.50%	4.50%	12.50%	7.84%	9.48%	7.86%	8.71%
9	SWX	9.03%	6.00%	4.50%	5.00%	2.50%	8.00%	0.50%	4.00%	4.36%	-4.34%	2.35%	5.19%
10	WGL	4.52%	6.70%	4.00%	2.50%	5.00%	4.00%	1.50%	4.50%	4.03%	5.36%	2.05%	5.49%
11				4.70%	3.94%	4.35%	7.20%	2.80%	7.05%		5.99%	4.15%	5.95%
12	AVERAGES	6.44%	6.59%		4.33%			5.68%		5.22%		5.36%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 04/24/2009 (WATER COMPANIES) AND 03/13/2009 (NATURAL GAS LDC's)
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 04/24/2009 (WATER COMPANIES) AND 03/13/2009 (NATURAL GAS LDC's)
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THRU 3 (WATER) AND 1 THRU 10 (NATURAL GAS)
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 04/24/2009 (WATER COMPANIES) AND 03/13/2009 (NATURAL GAS LDC's)

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
CAPM COST OF EQUITY CAPITAL

DOCKET NO. W-01445A-08-0440
SCHEDULE WAR - 7, PAGE 1 OF 2

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AWR	k	=	1.87%	+ [	0.85	x	(	10.40%	-	5.30%	)]	=	6.21%
2	CWT	k	=	1.87%	+ [	0.85	x	(	10.40%	-	5.30%	)]	=	6.21%
3	WTR	k	=	1.87%	+ [	0.75	x	(	10.40%	-	5.30%	)]	=	5.70%
4	WATER COMPANY AVERAGE					0.82								6.04%
5	AGL	k	=	1.87%	+ [	0.75	x	(	10.40%	-	5.30%	)]	=	5.70%
6	ATO	k	=	1.87%	+ [	0.60	x	(	10.40%	-	5.30%	)]	=	4.93%
7	LG	k	=	1.87%	+ [	0.65	x	(	10.40%	-	5.30%	)]	=	5.19%
8	NJR	k	=	1.87%	+ [	0.65	x	(	10.40%	-	5.30%	)]	=	5.19%
9	GAS	k	=	1.87%	+ [	0.75	x	(	10.40%	-	5.30%	)]	=	5.70%
10	NWN	k	=	1.87%	+ [	0.60	x	(	10.40%	-	5.30%	)]	=	4.93%
11	PNY	k	=	1.87%	+ [	0.65	x	(	10.40%	-	5.30%	)]	=	5.19%
12	SJI	k	=	1.87%	+ [	0.65	x	(	10.40%	-	5.30%	)]	=	5.19%
13	SWX	k	=	1.87%	+ [	0.70	x	(	10.40%	-	5.30%	)]	=	5.44%
14	WGL	k	=	1.87%	+ [	0.65	x	(	10.40%	-	5.30%	)]	=	5.19%
15	NATURAL GAS LDC AVERAGE					0.67								5.26%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEYS "SELECTION & OPINIONS" PUBLICATION FROM 04/10/2009 THROUGH 05/29/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE GEOMETRIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2007 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES DURING THE SAME PEI THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2008 YEARBOOK.

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
CAPM COST OF EQUITY CAPITAL

DOCKET NO. W-01445A-08-0440
SCHEDULE WAR - 7, PAGE 2 OF 2

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AWR	k	=	1.87%	+ [	0.85	x	(	12.30%	-	5.50%	)]	=	7.65%
2	CWT	k	=	1.87%	+ [	0.85	x	(	12.30%	-	5.50%	)]	=	7.65%
3	WTR	k	=	1.87%	+ [	0.75	x	(	12.30%	-	5.50%	)]	=	6.97%
4	WATER COMPANY AVERAGE					0.82								7.43%
5	AGL	k	=	1.87%	+ [	0.75	x	(	12.30%	-	5.50%	)]	=	6.97%
6	ATO	k	=	1.87%	+ [	0.60	x	(	12.30%	-	5.50%	)]	=	5.95%
7	LG	k	=	1.87%	+ [	0.65	x	(	12.30%	-	5.50%	)]	=	6.29%
8	NJR	k	=	1.87%	+ [	0.65	x	(	12.30%	-	5.50%	)]	=	6.29%
9	GAS	k	=	1.87%	+ [	0.75	x	(	12.30%	-	5.50%	)]	=	6.97%
10	NWN	k	=	1.87%	+ [	0.60	x	(	12.30%	-	5.50%	)]	=	5.95%
11	PNY	k	=	1.87%	+ [	0.65	x	(	12.30%	-	5.50%	)]	=	6.29%
12	SJI	k	=	1.87%	+ [	0.65	x	(	12.30%	-	5.50%	)]	=	6.29%
13	SWX	k	=	1.87%	+ [	0.70	x	(	12.30%	-	5.50%	)]	=	6.63%
14	WGL	k	=	1.87%	+ [	0.65	x	(	12.30%	-	5.50%	)]	=	6.29%
15	NATURAL GAS LDC AVERAGE					0.67								6.39%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [ß (r_m - r_f)]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEYS "SELECTION & OPINIONS" PUBLICATION FROM 04/10/2009 THROUGH 05/29/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE ARITHMETIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2007 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES DURING THE SAME THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2008 YEARBOOK

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. W-01445A-08-0440
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.39%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.25%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.03%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.96%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.61%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.81%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.93%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	2.34%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.55%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.19%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.38%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	2.83%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	1.59%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	2.27%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.68%	3.60%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.39%	2.90%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	3.24%	2.80%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	2.85%	2.00%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.58%	1.30%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	CURRENT	0.10%	-6.10%	3.25%	0.50%	0.00% - 0.25%	0.17%	4.14%	6.01%	7.59%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 05/29/2009
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 05/29/2009
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2007
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. W-01445A-08-0440
SCHEDULE WAR - 9

AVERAGE CAPITAL STRUCTURES OF SAMPLE WATER COMPANIES

LINE NO.		AWR	PCT.	CWT	PCT.	WTR	PCT.	WATER COMPANY AVERAGE	PCT.
1	DEBT	$ 266.5	46.2%	$ 287.5	41.6%	$ 1,248.1	54.1%	$ 450.5	50.4%
2									
3	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
4									
5	COMMON EQUITY	310.5	53.8%	402.9	58.4%	1,058.4	45.9%	443.0	49.6%
6									
7	TOTALS	$ 577.0	100%	$ 690.4	100%	$ 2,306.5	100%	$ 893.5	100%

AVERAGE CAPITAL STRUCTURES OF SAMPLE NATURAL GAS COMPANIES

LINE NO.		AGL	PCT.	ATO	PCT.	LG	PCT.	NJR	PCT.	GAS	PCT.
1											
2											
3	DEBT	$ 1,675.0	50.3%	$ 2,119.8	50.8%	$ 389.2	44.4%	$ 455.1	38.5%	$ 448.0	31.5%
4											
5	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.5	0.1%	0.0	0.0%	0.6	0.0%
6											
7	COMMON EQUITY	1,652.0	49.7%	2,052.5	49.2%	486.5	55.5%	727.0	61.5%	973.1	68.4%
8											
9	TOTALS	$ 3,327.0	100%	$ 4,172.3	100%	$ 876.2	100%	$ 1,182.1	100%	$ 1,421.7	100%
10											
11											
12		NWN	PCT.	PNY	PCT.	SJI	PCT.	SWX	PCT.	WGL	PCT.
13											
14	DEBT	$ 512.0	44.9%	$ 794.3	47.2%	$ 332.8	39.2%	$ 1,185.5	51.0%	$ 603.7	38.5%
15											
16	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	100.0	4.3%	28.2	1.8%
17											
18	COMMON EQUITY	628.4	55.1%	887.2	52.8%	515.3	60.8%	1,037.8	44.7%	935.1	59.7%
19											
20	TOTALS	$ 1,140.4	100%	$ 1,681.5	100%	$ 848.1	100%	$ 2,323.3	100%	$1,567.0	100%
21											
22											
23		NATURAL GAS LDC				WATER & LDC					
24		AVERAGE	PCT.			AVERAGE	PCT.				
25											
26	DEBT	$ 851.5	45.9%			$ 651.0	47.4%				
27											
28	PREFERRED STOCK	12.9	0.7%			6.5	0.5%				
29											
30	COMMON EQUITY	989.5	53.4%			716.2	52.1%				
31											
32	TOTALS	$ 1,854.0	100%			$ 1,373.7	100%				

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS

ARIZONA WATER COMPANY

DOCKET NO. W-01445A-08-0440

SURREBUTTAL TESTIMONY ON COST OF CAPITAL

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 7, 2009

EXHIBIT
R-33
SUBMITTED
DOCKET

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10 ATTACHMENT E – Value Line Selected Yields August 7, 2009

11 ATTACHMENT F – Value Line Water Industry Update July 24, 2009

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INTRODUCTION

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

A. My name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office, located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state the purpose of your surrebuttal testimony.

A. The purpose of my surrebuttal testimony is to respond to AWC's rebuttal testimony on RUCO's recommended rate of return on invested capital (which includes RUCO's recommended cost of debt and cost of common equity) for the Company's water operations in Arizona.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes. On June 12, 2009, I filed direct testimony with the ACC. My direct testimony addressed the cost of capital issues that were raised in AWC's Application that was filed on August 22, 2008.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains four parts: the introduction that I have just presented; a summary of AWC's rebuttal testimony; a comparison of the cost of capital recommendations being made by the parties to the case; and a section on the cost of equity capital.

SUMMARY OF ARIZONA WATER COMPANY'S REBUTTAL TESTIMONY

Q. Have you reviewed AWC'S rebuttal testimony?

A. Yes. I have reviewed the rebuttal testimony of Dr. Thomas M. Zepp, which was filed on July 8, 2009.

Q. Please summarize Dr. Zepp's rebuttal testimony.

A. Dr. Zepp continues to advocate an unreasonably high 12.40 percent cost of common equity for AWC. His rebuttal testimony takes issue with the inputs that I have used in both my DCF model and my CAPM model (which used both an arithmetic and geometric mean to arrive at the market risk premium component) and my use of a sample of natural gas distribution companies.

COMPARISON OF RECOMMENDATIONS

Q. Are the parties to the case in agreement on the issue of capital structure?

A. Yes. The parties to the case are presently in agreement on the issue of capital structure. In AWC's rebuttal testimony, the Company adopted ACC Staff witness David C. Parcell's recommended capital structure which includes short-term debt. RUCO has also adopted the Company's revised capital structure which results in a lower weighted average cost of capital. The Company, ACC Staff, and RUCO are now recommending a capital structure comprised of 4.80 percent short-term debt, 49.35 percent long-term debt and 45.85 percent common equity.

Q. Is RUCO also in agreement with the Company's revised costs of debt?

A. Yes. RUCO is now recommending that the Commission adopt the Company's revised costs of 3.00 percent short-term debt and 6.83 percent long-term debt.

Q. Are AWC, ACC Staff and RUCO in agreement on a cost of equity capital for the Company?

A. No. As is typical in utility rate cases there is substantial disagreement on a cost of common equity.

Q. Please summarize the costs of common equity and the weighted average costs of capital ("WACC") that are being recommended by the parties to the case.

A. In regard to the cost of common equity, the parties to the case are presently recommending the following estimates:

AWC	12.40%
ACC Staff	10.00%
RUCO	8.33%

As can be seen in the above comparison, the Company-proposed cost of equity capital is 407 basis points higher than my recommended cost of equity capital. The difference between my recommended cost of equity

and Mr. Parcell's recommended cost of equity is 167 basis points. The WACC, based on the costs of debt and equity noted above, being recommended by the parties to the case are as follows:

AWC	9.20%
ACC Staff	8.10%
RUCO	7.33%

As can be seen above, there is presently a 187 basis point difference between the Company-proposed 9.20 percent WACC and RUCO's recommended WACC of 7.55 percent. RUCO and ACC Staff's recommended WACC are within 77 basis points of each other.

COST OF EQUITY CAPITAL

Q. Has there been any recent activity in regard to interest rates?

A. Yes. On June 24, 2009, after a two-day meeting, the Federal Reserve chose not to enlarge its program to buy Treasury bonds to spur growth and stated again that its key Federal Funds interest rate will remain near zero "for an extended period." The Fed also announced that it will proceed with its previously announced plans to buy up to $300 billion in long-term U.S. Treasury bonds by autumn and up to $1.25 trillion in mortgage-backed securities by year's end. The Fed further stated that it

would "continue to evaluate the timing and overall amounts" of the purchases of the aforementioned financial instruments.[1]

Q. Has Value Line published an update on the water and natural gas utility industries since you filed your direct testimony?

A. Yes. Value Line published its quarterly updates on the water and natural gas utility industries on July 24, 2009 and June 12, 2009 respectively.

Q. Have you revised your recommended 8.33 percent cost of common equity for AWC based on more recent information on interest rates and the latest Value Line data on the water and natural gas utility industries?

A. No. The updated Value Line data produced no change to my recommended 8.33 percent cost of common equity estimate which is still reasonable given the current state of interest rates and the current state of the economy.

Q. Please comment on Dr. Zepp's restatements of the results of your DCF and CAPM estimates?

A. Dr. Zepp's restatements should not be afforded any weight. As I will explain throughout the remainder of my testimony, there is nothing incorrect with the inputs or assumptions that I have relied on in both my DCF and CAPM models.

[1] Reddy, Sudeep and Geoffrey T. Smith, "Fed on Hold as Slump Eases" The Wall Street Journal, June 25, 2009.

Q. In his direct testimony, Dr. Zepp calculated an average beta of 0.98 for his sample water companies. What is the current average beta for those same companies?

A. Based on updated information published by Value Line on July 24, 2009, the average beta for Dr. Zepp's sample water companies has fallen to 0.82 indicating that risk (as measured by beta) for water company stocks has declined since he filed his direct testimony.

Q. Please address Dr. Zepp's criticism that the 5-year Treasury instrument that you used in the risk free component of your CAPM models is not the correct proxy to value common stocks.

A. Dr. Zepp argues that a long-term treasury instrument is the appropriate proxy for the risk free rate of return in the CAPM model. But the fact is that regulated utilities typically file for rates within a three to five-year period and the investment community is aware of that fact and understands the effect of rate case proceedings on earnings, dividend and book value growth. Information on rate case proceedings is available to investors through SEC filings, investment research firms such as Value Line, and the mainstream financial press. Any investor who follows utilities would be aware of the impact that rate requests would have on future earnings and would base his or her investment decisions on that information (Attachment A).

Q. Can you cite another reason why you believe the 5-year treasury instrument used in your CAPM analysis is appropriate?

A. Yes. Professional analysts at investment services such as Value Line and Zacks Investment Research typically do not make projections beyond five years. In fact, the Federal Energy Regulatory Commission ("FERC") places more emphasis on short-term projections (i.e. one to five years) in the multi-stage DCF model that Dr. Zepp used to arrive at his 12.40 percent cost of equity recommendation.

Q. Please explain how the FERC places more emphasis on short-term projections in the multi-stage DCF model.

A. The multi-stage DCF model required by the FERC weighs short-term estimates of growth, similar to the one to five-year projections that I relied on to develop the "g" component in my single stage DCF model, by a factor of two-thirds. The FERC's rationale is that short-term estimates of growth are more predictable and deserve more weight than long-term estimates such as the equally-weighted long-term estimates of growth used in the multi-stage DCF model that Dr. Zepp has relied on. This is explained in the following excerpt from the FERC's Cost-of-Service Rates Manual (Attachment B):

> "**Return on Equity or Cost of Equity:** This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow (DCF) analysis of a proxy group of publicly held natural gas companies. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short-term growth estimates and the other long-term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in

> determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long-term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk."

Q. Please explain why Dr. Zepp's criticism regarding the use of a geometric mean in a CAPM analysis is unfounded.

A. The information on both the geometric and arithmetic means, published by Morningstar, is widely available to the investment community. For this reason alone I believe that the use of both means in a CAPM analysis is appropriate.

The best argument in favor of the geometric mean is that it provides a truer picture of the effects of compounding on the value of an investment when return variability exists. This is particularly relevant in the case of the return on the stock market, which has had its share of ups and downs over the 1926 to 2007 observation period used in my CAPM analysis.

Q. Can you provide an example to illustrate the difference between arithmetic and geometric means?

A. Yes. The following example may help. Suppose you invest $100 and realize a 20.0 percent return over the course of a year. So at the end of year 1, your original $100 investment is now worth $120. Now let's say that over the course of a second year you are not as fortunate and the value of your investment falls by 20.0 percent. As a result of this, the $120 value of your original $100 investment falls to $96. An arithmetic

mean of the return on your investment over the two-year period is zero percent calculated as follows:

$$(\text{year 1 return} + \text{year 2 return}) \div \text{number of periods} =$$

$$(20.0\% + -20.0\%) \div 2 =$$

$$(0.0\%) \div 2 = \underline{\underline{0.0\%}}$$

The arithmetic mean calculated above would lead you to believe that you didn't gain or lose anything over the two-year investment period and that your original $100 investment is still worth $100. But in reality, your original $100 investment is only worth $96. A geometric mean on the other hand calculates a compound return of negative 2.02 percent as follows:

$$(\text{year 2 value} \div \text{original value})^{1/\text{number of periods}} - 1 =$$

$$(\$96 \div \$100)^{1/2} - 1 =$$

$$(0.96)^{1/2} - 1 =$$

$$(0.9798) - 1 =$$

$$-0.0202 = \underline{\underline{-2.02\%}}$$

The geometric mean calculation illustrated above provides a truer picture of what happened to your original $100 over the two-year investment period.

As can be seen in the preceding example, in a situation where return variability exists, a geometric mean will always be lower than an arithmetic mean, which probably explains why utility consultants typically put up a strenuous argument against the use of a geometric mean.

Q. Can you cite any other evidence that supports your use of both a geometric and an arithmetic mean?

A. Yes. In the third edition of their book, Valuation: Measuring and Managing the Value of Companies, authors Tom Copeland, Tim Koller and Jack Murrin ("CKM") make the point that, while the arithmetic mean has been regarded as being more forward looking in determining market risk premiums, a true market risk premium may lie somewhere between the arithmetic and geometric averages published in Morningstar's SBBI yearbook.

Q. Please explain.

A. In order to believe that the results produced by the arithmetic mean are appropriate, you have to believe that each return possibility included in the calculation is an independent draw. However, research conducted by CKM demonstrates that year-to-year returns are not independent and are actually auto correlated (i.e. a relationship that exists between two or more returns, such that when one return changes, the other, or others, also change), meaning that the arithmetic mean has less credence. CKM also

explains two other factors that would make the Morningstar arithmetic mean too high. The first factor deals with the holding period. The arithmetic mean depends on the length of the holding period and there is no "law" that says that holding periods of one year are the "correct" measure. When longer periods (e.g. 2 years, 3 years etc.) are observed, the arithmetic mean drops about 100 basis points. The second factor deals with a situation known as survivor bias. According to CKM, this is a well-documented problem with the Morningstar historical return series in that it only measures the returns of successful firms, that is, those firms that are listed on stock exchanges. The Morningstar historical return series does not measure the failures, of which there are many. Therefore, the return expectations in the future are likely to be lower than the Morningstar historical averages. After conducting their analysis, CKM concluded that 4.00 percent to 5.50 percent is a reasonable forward looking market risk premium. Adding the current 5-year Treasury yield of 2.63 percent to these two estimates indicates a cost of equity range of 6.63 percent to 8.13 percent. Taking into consideration the fact that utilities generally exhibit less risk than industrials, a return in the low end of this range would be reasonable. In fact, my 8.33 percent cost of common equity estimate is 20 basis points more than the high end of the range exhibited above.

Q. Has the Commission authorized rates of return that were derived through the use of both arithmetic and geometric means in prior decisions?

A. Yes, a case that specifically comes to mind involved UNS Gas Inc., in which Decision No. 70011, dated November 27, 2007, stated the following:

> "We agree with the Staff and RUCO witnesses that it is appropriate to consider the geometric returns in calculating a comparable company CAPM because to do otherwise would fail to give recognition to the fact that many investors have access to such information for purposes of making investment decisions."

In the UNS Gas, Inc. case, the ACC Staff witness was Mr. Parcell who, as I do, consistently relies on both arithmetic and geometric means in our CAPM analyses.

Q. Can you provide further support for the reasonableness of the market risk premiums used in your CAPM models?

A. Yes. In his direct testimony in a prior Arizona Public Service Company ("APS") rate case proceeding, RUCO consultant Stephen G. Hill makes the argument for market risk premiums ranging from 4.0 percent to 6.0 percent[2] (Attachment C). On page 46 of his APS testimony, Mr. Hill supports his argument for lower market risk premiums by citing two scholarly articles on the subject published by noted academics. In the first paper titled *The Equity Premium*, published in 2002, Eugene Fama and Kenneth French take the position that Ibbotson Associates' historical

[2] Lines 25 through 29 of page 45, and lines 1 through 4 of page 46 of the direct testimony of RUCO consultant Stephen G. Hill, Docket No. E-01345A-05-0816 et al.

market risk premiums (now published by Morningstar) have overstated investor expectations.

Q. Can you cite any other sources that support Mr. Hill's views, in his APS rate case testimony, that 4.0 percent to 6.0 percent is a reasonable market risk premium on a forward-looking basis?

A. Yes. During the 39th annual Financial Forum of the Society of Utility and Regulatory Financial Analysts, which was held at Georgetown University in Washington D.C. on April 19 and 20, 2007, I had the opportunity to hear the views of Aswath Damodaran, Ph. D. and Felicia C. Marston, Ph. D., professors of finance from New York University and the University of Virginia respectively, who have conducted empirical research on this subject. Dr. Damodaran and Dr. Marston advocated 4.0 to 5.5 percent estimates during a panel discussion that provided both professors with the opportunity to explain their research on the equity risk premium and to answer questions from other financial analysts in attendance. Each of the panelists stated that they believed that a reasonable market risk premium fell between 4.0 percent and 5.0 percent when asked to provide estimates based on their research.

...

Q. What would your CAPM results be if the market risk premiums of 4.0 percent to 6.0 percent, advocated by Mr. Hill, were used in your CAPM model?

A. Using an updated 2.63 percent yield on a 5-year Treasury instrument (r_f), an updated beta of 0.82 noted earlier in my surrebuttal testimony, and the market risk premiums (r_m - r_f) of 4.0 percent to 6.0 percent, advocated by Mr. Hill, in my CAPM model produces the following results for water utilities:

<u>Using a 4.0% Market Risk Premium</u>

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

$$k = 2.63\% + [\,0.82\,(4.0\%)\,]$$

$$k = 2.63\% + 3.28\%$$

$$k = \underline{5.91\%}$$

<u>Using a 6.0% Market Risk Premium</u>

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

$$k = 2.63\% + [\,0.82\,(6.0\%)\,]$$

$$k = 2.63\% + 4.92\%$$

$$k = \underline{7.55\%}$$

The 6.73 percent average of these results for water utilities are almost identical to the 6.74 percent average (using both arithmetic and geometric means) that I obtained in my CAPM that I used to calculate my

recommended 8.33 percent cost of common equity. When the market risk premium information noted above is taken into consideration, it is clear that Dr. Zepp's market risk premium inputs, as opposed to mine, appear to be out of line.

Q. Do you have any data that supports a 4.00 percent equity risk premium during the market crises which unfolded in September of 2008?

A. Yes. In September 2008 Dr. Damodaran, who I noted earlier in my testimony, presented a paper titled Equity Risk Premium (ERP): Determinants, Estimation and Implications (Attachment D), which contained an October update that presented data on the swings in implied equity risk premium that occurred between September 12, 2008 and October 16, 2008. During that time frame, implied equity risk premiums ranged from 4.20 percent to 6.39 percent. The 5.30 percent mean average of that range is 98 basis points lower than the 6.28 percent average of my market risk premium using both geometric and arithmetic means for water and gas companies.

Q. Do you believe that the results produced by your CAPM models are reflective of the current interest rate environment?

A. Yes, when one considers the current state of lower interest rates on low risk investments such as U.S. Treasury instruments and various bank certificates of deposit (Attachment E). The results of my CAPM analyses

(using both arithmetic and geometric means) are simply reflecting this situation. From the perspective that public utilities have traditionally been viewed as safe investments, all things being equal it is not reasonable to believe that their costs of equity capital should be at the 12.40 percent level advocated by Dr. Zepp.

Q. Please address Dr. Zepp's point, regarding the market risk premium, that common shareholders bear a higher risk than bond holders and expect a higher return than the yields of utility debt instruments.

A. I do not disagree with Dr. Zepp on this point. The question is how much more of a risk premium is merited for a low risk regulated monopoly such as AWC (Value Line has described the water utility industry as being the last true monopoly in the U.S.). My recommended 8.33 percent cost of common equity capital is 533 basis points higher than AWC's 3.00 percent cost of short-term debt and 150 basis points higher than the Company's 6.83 percent cost of long-term debt. It is also 119 basis points higher than the recent 7.14 percent yield on Baa/BBB-rated utility bond and 254 basis points higher than the recent 5.79 percent yield on an A-rated utility bond.

...

Q. Please comment on the information presented on page 46 of Dr. Zepp's rebuttal testimony, where he cites several recent instances in which certain water companies had to issue debt at 7.76 percent and 8.30 percent.

A. I disagree that a single debt issuance at a particular point in time should be the sole reason for increasing my recommended cost of equity. In fact if AWC were to issue debt at a higher rate of interest, its cost would be averaged with its existing 6.83 percent cost of long-term debt, which would mitigate the effects of the higher cost issuance.

Q. Is there another reason why you believe Dr. Zepp's argument does not merit a higher return on common equity.

A. Yes. Value Line has consistently taken the position that water utility stocks are attractive to investors given the current economic climate. In the most recent Value Line update on the water utility industry, dated July 24, 2009, Value Line analyst Andre J. Costanza had this to say:

> "Water Utility providers have fared pretty well of late, with increasingly favorable regulatory backing boosting revenues and driving strong bottom line advances in the first quarter. Additional improvements are likely to evolve on the regulatory front and should enable most in this space to maintain their recent earnings momentum throughout the remainder of the year."

> "Despite the recent spurts of price momentum, the market remains extremely volatile overall. The tough macroeconomic environment creates a difficult backdrop, which ought to favor industries that are perceived as relative safe havens, a trait typically exemplified by water utilities' historically steady dividend growth."

Mr. Costanza further stated:

> "Although the stocks in this group do not stand out either for the coming six to 12 months or the 3- to 5-year pull, investors with a cautious bent may want to have a closer look. Water utilities will probably be a far more stable place to be if the market remains volatile, a fair bet given the glum economic indicators that have continued to come out."

Q. How does your recommended 8.33 percent cost of common equity compare to the most recent Value Line projections for the water utility industry?

A. As can be seen in Attachment F, Value Line is currently projecting a 7.00 percent rate of return on book common equity for the water utility industry as a whole through 2014. This is 133 basis points lower than my recommended 8.33 percent cost of common equity.

Q. Please address Dr. Zepp's criticism of your DCF analysis, which takes into consideration the concept that a utility's market-to-book ratio will move toward a value of 1.0 if regulators set a utility's rate of return at a level that is equal to the cost of capital of firms with similar risk.

A. A utility's market price should equal its book price over the long run if regulators allow a rate of return that is equal to the utility's cost of capital. *That is assuming that the utility's rate of return ("ROR") is comparable to the rates of return of other firms in the same risk class.*[3] For example, if a hypothetical utility's book price is $20.00 per share and regulators adopt a

[3] An in-depth discussion of market-to-book ratios can be found in Chapter 10 of Roger A. Morin's text Regulatory Finance, Utilities' Cost of Capital.

rate of return that is equal to the utility's cost of capital of 10.0%, the utility will earn $2.00 per share ("EPS"). With earnings of $2.00 per share, and a market required rate of return on equity of 10.00%, for firms in the utility's risk class, the market price of the utility's stock will set at $20.00 per share ($2.00 EPS ÷ 10.0% ROR = $20.00 per share price). If the utility records earnings that are higher than the earnings of other firms with similar risk, the market value of the utility's shares will increase accordingly, (e.g. $2.50 EPS ÷ 10.0% ROR = $25.00 per share). On the other hand, if the utility posts lower earnings, the stock's market price will fall below book value, (e.g. $1.50 EPS ÷ 10.0% ROR = $15.00 per share).

Because of economic forces beyond the control of regulators, it is not reasonable to assume that the utility will have earnings that match those of firms of similar risk in every year of operation. In some years, earnings may drop causing the market-to-book ratio to fall below 1.0, while in other years the utility may have earnings that exceed those of other firms in its risk classification. However, over the long run the utility's earnings should average out to the earnings that are expected based on its level of risk. These average earnings over time will result in a market-to-book ratio of 1.0. It has been suggested that regulators should set a utility's rate of return at a level that is slightly higher than that of firms in the same risk class of the hypothetical utility. In theory, this will send a message to investors that average long-term earnings will not be less than what is expected. A 1.0 ratio may never be achieved in practice and many

investors may not even care what the market-to-book ratio is as long as they receive their required rate of return. In this respect, a utility stock is similar to a corporate bond whose value fluctuates as interest rates move above or below the stated yield on the bond. As long as the bond provides the level of income (i.e. the stated interest payment in the case of a bond or a dividend payment in the case of a utility stock) that the investor expects, the price of the instrument at any given point in time is immaterial (so long as the intent is to hold the bond until maturity or the utility stock over a long-term period).

Q. Does your recommended cost of equity take into consideration the theoretical concepts that you have just described?

A. Yes. As I just explained, in theory, a market-to-book ratio of 1.0 would be achieved if a utility's rate of return equaled the cost of capital that is close to the returns of firms with similar risk. The CAPM analysis that I performed earlier in this testimony (using the current yield on a 5-year U.S treasury note and the revised beta and market risk premium inputs advocated by Mr. Hill) indicates that the rate of return for a firm with AWC's level of risk is 7.63 percent. This being the case, the adoption of my recommended 8.33 percent cost of capital would be consistent with the theory I have presented above since it is 70 basis points higher than the aforementioned average 7.63 percent expected rate of return that theoretically produces a market price that is equal to book value.

Q. Are there any other reasons why your market-to-book ratio calculation is valid?

A. Yes. The utilities included in my samples, are engaged in unregulated activities to some degree. Because it is difficult to obtain a sample comprised only of "pure play" utilities, the calculation that I have employed in my DCF model helps to eliminate the impact that those unregulated operating segments would have on the market-to-book ratio of the utilities included in my sample.

Q. Please address Dr. Zepp's position that your internal and external growth rate estimates are subjective.

A. My growth rate estimates take into consideration both historic rates of growth as well as an evaluation of analysts' projections of growth for each projected year for the next five years as opposed to simply plugging in a final five-year estimate. As I stated in my direct testimony, it is the same methodology that produced a rate of return that the Commission adopted in a prior Southwest Gas rate case proceeding.

Q. Can you offer further support for your DCF growth rate estimates?

A. Yes. In the same text that Dr. Zepp cites in his rebuttal testimony, New Regulatory Finance, the book's author, Dr. Roger Morin, provides a DCF growth rate check (Attachment G). The reasonableness test offered by Dr. Morin is expressed as follows:

Dividend Growth = Risk Free Return + Risk Premium – Dividend Yield

Under the above formula the dividend yield element of the DCF ("D_1/P_0") is subtracted from results of a CAPM calculation ("r_f + [ß (r_m - r_f)]").

Q. How does your 6.25 percent and 6.44 percent water and natural gas growth estimates compare to the results obtained from the reasonableness test offered by Dr. Morin?

A Using the CAPM results presented above using the most recent 0.82 average Value Line beta for the water utilities in Dr. Zepp's sample, his preferred 20-year risk free rate of 4.67 percent, the 4.0 percent to 6.0 percent market risk premium (advocated by Mr. Hill in his APS testimony) and the average 3.08 and 4.98 percent dividend yield estimates for water and natural gas presented in my direct testimony, the following growth rate check results are obtained:

<u>Water - Using a 4.0% Market Risk Premium</u>

$$g = r_f + [\,ß\,(r_m - r_f)\,] - (D_1/P_0)$$

$$g = 4.67\% + [\,0.8.2\,(4.0\%)\,] - 3.08\%$$

$$g = 4.67\% + 3.28\% - 3.08\%$$

$$g = \underline{4.87\%}$$

Water - Using a 6.0% Market Risk Premium

$$g = r_f + [\,ß\,(r_m - r_f)\,] - (D_1/P_0)$$

$$g = 4.67\% + [\,0.82\,(6.0\%)\,] - 3.08\%$$

$$g = 4.67\% + 4.92\% - 3.08\%$$

$$g = \underline{6.51\%}$$

Gas - Using a 4.0% Market Risk Premium

$$g = r_f + [\,ß\,(r_m - r_f)\,] - (D_1/P_0)$$

$$g = 4.67\% + [\,0.67\,(4.0\%)\,] - 4.98\%$$

$$g = 4.67\% + 2.68\% - 4.98\%$$

$$g = \underline{2.37\%}$$

Gas - Using a 6.0% Market Risk Premium

$$g = r_f + [\,ß\,(r_m - r_f)\,] - (D_1/P_0)$$

$$g = 4.67\% + [\,0.67\,(6.0\%)\,] - 4.98\%$$

$$g = 4.67\% + 4.02\% - 4.98\%$$

$$g = \underline{3.71\%}$$

The growth rate check results for water utilities, obtained from Dr. Morin's reasonableness test, range from 4.87 percent to 6.51 percent or an average of 5.69 percent which is 56 basis points lower than my 6.25 percent DCF growth rate estimate for water utilities. The growth rate check results for natural gas utilities, range from 2.37 percent to 3.71 percent or an average of 3.04 percent which is 340 basis points lower than my 6.44 percent DCF growth rate estimate. Clearly my average growth

rate estimate of 6.33 percent for water and natural gas companies falls within the range of reasonableness using Dr. Morin's test.

Q. Please comment on Dr. Zepp's position that the Commission has to be consistent in adopting returns on common equity that are derived from specific methodologies that were used in prior cases.

A. I believe that the Commission has broad authority in setting allowed rates of return and can rely on whatever methodologies they choose to rely on as long as their final decision results in rates that are just and reasonable.

Q. Does your silence on any of the issues or positions addressed in the rebuttal testimony of the Company's witnesses constitute acceptance?

A. No, it does not.

Q. Does this conclude your surrebuttal testimony on AWC?

A. Yes, it does.

ATTACHMENT A

Jon Markman

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Posted 1/12/2005

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SuperModels

Invest in the coming global water shortage

Fresh water's getting scarce, and it has no substitutes. For investors in companies that can supply our increasingly thirsty planet, that spells opportunity.

By Jon D. Markman

Ten years ago next Monday, a massive earthquake rolled under the Japanese city of Kobe at dawn, toppling 140,000 buildings, causing 300 major fires, killing more than 5,000 people and leaving 300,000 homeless.

To help cover the story for the L.A. Times, I left my wife to care for our 10-day-old daughter and 2-year-old son and flew into the city with a small team of Los Angeles-based trauma doctors and nurses. We found a surreal, smoking ruin of a city with roads twisted like coils of rope, high-rises tilted at Dr. Seuss angles and thousands of middle-class families jammed into dingy, ice-cold rooms in the few public buildings left standing.

Just as in the tsunami zone of South Asia this month, the immediate health danger, besides a possible outbreak of disease, was a lack of fresh water. More than 75% of the city's water supply was destroyed when underground pipes fractured. As much as they desired pallets of drugs, food, blankets and tents sent from throughout Japan and abroad, the Kobe survivors coveted -- and needed -- clean, bottled water for cooking, drinking and bathing.

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Both incidents are a stark reminder that water is our most precious resource. Because it is seemingly ubiquitous in the United States, it is taken for granted. Massive snowstorms in California this month have loaded up the snowpack that provides water there, and rains in the Southeast are filling reservoirs in that part of the country.

The rest of the world, however, is not so fortunate.

Not making any more water

There is no more fresh water on Earth today than there was a million years ago. Yet today, 6 billion people share it. Since 1950, the world population has doubled, but water use has tripled, notes John Dickerson, an analyst and fund manager based in San Diego. Unlike petroleum, he adds, no technological innovation can ever replace water.

China, which is undergoing a vast rural-to-urban population migration, is emblematic of the places where water has become scarce. It has about as much

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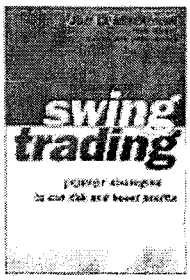

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water as Canada but 100 times more people. Per-capita water reserves are only about a fourth the global average, according to experts. Of its 669 cities, 440 regularly suffer moderate to critical water shortages.

Although not widely appreciated, water has been recognized by conservative investors as an investment opportunity -- and it has rewarded them. Over the past 10 years, the Media General water utilities index is up 133%, double the return of the **Dow Jones Utilities Index** ($UTIL). Over the past five years, water utilities are up 32% -- clobbering the flat returns of both the Dow Jones Utilities and the **Dow Industrials** ($INDU). One of water's key long-term value drivers as an investment, according to Dickerson: Demand is not affected by inflation, recession, interest rates or changing tastes.

Virtually all of the U.S. water utility stocks are regulated by states and counties, which makes them pretty dull. Governmental entities typically give utilities a monopoly in a geographic region, then set their profit margin a smidge above costs. Just about the only distinguishing factor among them are the growth rates of their regions and their ability to efficiently manage their underground pipe and pumping infrastructure. Among the best are **Aqua America** (WTR, news, msgs) of Philadelphia, **Southwest Water** (SWWC, news, msgs) of Los Angeles; **California Water Service Group** (CWT, news, msgs), based in San Jose, Calif.; and **American States Water** (AWR, news, msgs) of San Dimas, Calif.

In a moment, I'll offer a couple of potentially more impactful ways to invest in water, but first let's look a little more broadly at world demand.

Aquifers in India are being sucked dry

The tsunami has focused attention on water demand in South Asia -- and it's a good thing, as it was already reaching critical status in rural areas. Several decades ago, farmers in the Indian state of Gujarat used oxen to haul water in buckets from a few feet below the surface. Now they pump it from 1,000 feet below the surface. That may sound good, but they have been drawing water from the earth to feed a mushrooming population at such a terrific rate that ancient aquifers have been sucked dry -- turning once-fertile fields slowly into sand.

According to New Scientist magazine, farmers using crude oilfield technology in India have drilled 21 million "tube wells" into the strata beneath the fields, and every year millions more wells throughout the region -- all the way to Vietnam -- are being dug to service water-needy crops like rice and sugar cane. The magazine quoted research from the annual Stockholm Water Symposium that the pumps that transformed Indian farming are drawing 200 cubic kilometers of water to the surface each year, while only a fraction is replaced by monsoon

rains. At this rate, the research suggested, groundwater supplies in some areas will be exhausted in five to 10 years, and millions of Indians will see their farmland turned to desert.

In China, the magazine reported, 30 cubic kilometers more water is being pumped to the surface each year than is replaced by rain -- one of the reasons that the country has become dependent on grain imports from the West. This is not just an issue for agriculture. Earlier this year, the Indian state of Kerala ordered the **PepsiCo** (PEP, news, msgs) and **Coca-Cola** (KO, news, msgs) bottling plants closed due to water shortages, costing the companies millions of dollars.

In this country, shareholder activists already are lobbying companies to share water-dependency concerns worldwide with their stakeholders in their financial statements.

Water, water everywhere, but . . .

The central problem is that less than 2% of the world's ample store of water is fresh. And that amount is bombarded by industrial pollution, disease and cyclical shifts in rain patterns. Its increasing scarcity has impelled private companies and countries to attempt to lock up rights to key sources. In an article last month, the Christian Science Monitor suggested that the next decade may see a cartel of water-exporting countries rivaling the Organization of Petroleum Exporting Countries for dominance in the world economy.

"Water is blue gold; it's terribly precious," Maude Barlow, chair of the Council of Canadians, told the Monitor. "Not too far in the future, we're going to see a move to surround and commodify the world's fresh water. Just as they've divvied up the world's oil, in the coming century, there's going to be a grab."

Besides the domestic water utilities listed above -- and similarly plodding foreign utilities such as **United Utilities** (UU, news, msgs) of the United Kingdom, which sports a 6.9% dividend yield, and **Suez** (SZE, news, msgs) of France -- investors interested in the sector can consider a number of variant plays. None are extremely exciting, but my guess is that, over the next few years, some more interesting purification technologies will emerge, along with, perhaps, a vibrant attempt at worldwide industry consolidation.

One current idea is Tennessee-based copper pipe and valve maker **Mueller Industries** (MLI, news, msgs), a $1 billion business with a trailing price/earnings multiple of 15 that is still not expensive despite a 47% run-up in the past year. Its leading outside investor is **Berkshire Hathaway** (BRK.A, news, msgs), the

investment vehicle of legendary investor Warren Buffett.

Another is flow-control products maker **Watts Water Technologies** (WTS, news, msgs), which is a little richer at a $975 million market cap and a trailing P/E multiple of 19, but is still owned by several leading value managers, including Mario Gabelli.

And possibly the most interesting is **Consolidated Water** (CWCO, news, msgs), a $160 million company based in the Cayman Islands that specializes in developing and operating ocean-water desalinization plants and water-distribution systems in areas where natural supplies of drinking water are scarce, such as the Caribbean and South America. It currently supplies water to Belize, Barbados, the British Virgin Islands and the Bahamas, and it has expansion plans. It is the most expensive, but it may also have the greatest growth prospects. Of all of these, it is up the most over the past five years, a relatively steady 355%.

Of course, there is one other benefit to water investing: When these companies say they're going to do a dilutive deal, it's not something to worry about.

Fine Print

Dickerson runs a hedge fund in San Diego strictly focused on water investing, the Summit Water Equity Fund. . . To learn more about Southwest Water, click here. . . . To learn more about California Water Service Group, which runs systems in New Mexico, Hawaii and Washington State, as well as California, click here. . . . To learn more about American States Water, click here. . . To learn more about Mueller, click here, and, for Consolidated Water, click here. . . . Seems like talk is cheap. Since mid-December, the value of the company radio personality Howard Stern is leaving, **Viacom** (VIA.B, news, msgs), has risen 9% while the value of the company he's headed to, **Sirius Satellite Radio** (SIRI, news, msgs), is down 13.5%. . . . For background on the Kobe earthquake, approaching its 10th anniversary, click here and here.

Jon D. Markman is publisher of StockTactics Advisor, an independent weekly investment newsletter, as well as senior strategist and portfolio manager at Pinnacle Investment Advisors. While he cannot provide personalized investment advice or recommendations, he welcomes column critiques and comments at jon.markman@gmail.com; put COMMENT in the subject line. At the time of publication he held positions in the following stocks mentioned in this column: Coca-Cola.

ATTACHMENT B

Cost-of-Service Rates Manual

Federal Energy Regulatory Commission
888 North Capitol Street, N.E.
Washington, D.C. 20426
United States of America
www.ferc.gov

June 1999

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$159,602,000, is equity financed. This means that the owners of Pipeline U.S.A. used their own funds to finance this portion of their investment.

** Pipeline U.S.A. issues its own debt which is not guaranteed by its parent, has its own bond rating and its capital structure is comparable to other equity capitalizations approved by the Commission. Therefore, Pipeline U.S.A. meets the Commission's criteria for using its own capital structure for setting its rates.*

Cost of Debt: This refers to the cost of long term debt incurred by the pipeline to construct or expand the pipeline. For ongoing pipelines that have been issuing debt, we use the actual imbedded cost of debt in the capital structure. The actual imbedded cost of debt is the weighted average of all the debt issued and the cost at which the debt was issued. For new pipelines that have indicated that they would issue debt to finance their investment, but have not yet actually issued the debt, we compute the cost of debt based on a projection, or recent historical debt cost such as historical average Baa utility bonds (Moody's Bond Survey), which is the most prevalent rating for utilities. We also use Moody's to compute the cost of debt if we decide use of a hypothetical capital structure is appropriate.

A-8, column 3, shows the cost of debt of Pipeline U.S.A. of 8.25%. The cost of debt represents a return to Pipeline U.S.A.'s bondholders. The debt return dollars appearing in Column 5 represents the cost to Pipeline U.S.A. to pay the interest on the debt to its bondholders. This debt return, or interest on debt, of $30,723,000 as shown in column (5) is included in the Return component of the cost-of-service.

Return on Equity or Cost of Equity: This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow

(DCF) analysis of a proxy group of publicly held natural gas companies. The Commission currently uses a two-stage Discounted Cash Flow (DCF) methodology. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short term growth estimates and the other long term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk. It is assumed, that most pipelines face risks that would place them in the middle of the zone of reasonableness. However, a case could be made depending on the facts of the specific pipeline that the return on equity should be outside the zone. As an example, a pipeline with a high debt capitalization ratio is usually considered more risky and thus, a higher return on equity would be expected.

We have determined that a reasonable return on equity for Pipeline U.S.A. is 14.00%. This return was at the high end of our range of equity returns because Pipeline U.S.A. is a relatively new pipeline company with a high debt capitalization ratio. The equity portion of the return permitted to be collected in rates is $22,344,000 shown in column (5) of A-8.

Pretax Return. Pretax return is the amount earned by a pipeline before income taxes and debt interest payments. Pretax return is often calculated for pipelines and used to further settlement negotiations. Using a pretax return figure can avoid the lengthy discussions and debates that surround the issues of capitalization ratios and ROE calculations and analyses. Use of a pretax return reduces these issues down to one number, a pretax percentage that can easily be compared to other pipeline's pretax returns. The pretax return figure

ATTACHMENT C

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY

OF

STEPHEN G. HILL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 18, 2006

Schedule 8 attached to this testimony shows the detail regarding the CAPM analysis. The average beta coefficients for the electric utility sample group was 0.83. Schedule 8 shows a CAPM cost of capital for the electric companies ranging from 9.23% to 10.56%.

Schedules 9 and 10 shows the theoretical basis and the data and calculations, respectively, for the Modified Earnings Price Ratio (MEPR) analysis. The MEPR analysis indicates a current cost of equity capital for electric companies in a narrow range from 8.79% to 9.13%. Finally, Schedule 11 attached to this testimony contains the supporting detail for the Market-to-Book Ratio (MTB) analysis, which indicates a current cost of equity capital for the electric utility companies of 9.31% (near-term) to 9.38% (long-term).

C. SUMMARY

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY CAPITAL COST ANALYSES FOR THE SAMPLE GROUP OF SIMILAR-RISK ELECTRIC UTILITY COMPANIES.

A. My analysis of the cost of common equity capital for the sample group of electric utility companies is summarized in the table below.

METHOD	Electric Utility Companies
DCF	9.44%
CAPM	9.23%/10.56%
MEPR	9.13%/8.79%
MTB	9.31%/9.38%

For the electric utility sample group, the DCF result is 9.44%. In addition, the corroborating cost of equity indications (MEPR, MTB, and CAPM) indicate that DCF result is reasonable. Averaging the lowest and highest results of all the corroborative analyses for the electric companies produces and equity cost range of 9.11% to 9.69%,

with a mid-point of 9.40%, only 4 basis points below the DCF result.

Therefore, weighing all the evidence presented herein, my best estimate of the cost of equity capital for a company like Arizona Public Service, facing similar risks as this group of electric utilities, ranges from 9.25% to 9.75%, with a mid-point of 9.50%.

Q. ARE THERE OTHER FACTORS TO BE CONSIDERED BEFORE DETERMINING A POINT-ESTIMATE FOR APS WITHIN A REASONABLE RAGE FOR SIMILAR-RISK FIRMS?

A. Yes. First, the electric sample group companies have similar operating risk to APS. The average S&P business risk score of my sample of electric utilities is 6—the same as that for APS. Therefore, on that basis there would be no reason to adjust the equity return from the mid-point of a reasonable range. However, because the capital structure I recommend for ratesetting purposes contains considerably more common equity and less debt than average for the sample group, APS, prospectively will have less financial risk than the sample group and should be awarded an equity return below the mid-point of a reasonable range.

Q. IS THERE A RECOGNIZED METHOD WITH WHICH DIFFERENCES IN FINANCIAL RISK CAN BE QUANTIFIED?

A. Yes. The cost of equity capital is affected by the capital structure a company employs. When a company increases the proportion of debt in its capital structure, it increases the riskiness of its equity. Financial risk (created by the use of debt in the capital structure) causes investors to demand a higher rate of return; that is, financial risk increases the cost of equity capital.

The impact of debt leverage on the cost of equity capital can be approximated through an examination of the changes in beta, which occur when leverage is increased or decreased. The Value Line betas for the sample companies used in my cost of capital analysis in this proceeding reflect the market's (investors') perception of both the business risks and the financial risks of a firm. That is, one portion of the beta of a firm is

related to the business risk of the firm (the risk inherent in its operations) and one portion of the beta is related to the financial risk of that firm (the risk associated with the use of debt). Therefore, if a firm elects to finance its operations with debt as well as equity, the beta coefficient of that firm will reflect both the business and financial risk. When a firm uses debt to finance its operations, the beta can also be referred to as a "levered" beta (i.e., a beta coefficient that includes the impact of debt leverage).

The average beta coefficient of the sample group of utilities can be "unlevered." That is, the beta-risk related to the level of debt capital used by the firm can be removed. "Unlevering the betas" amounts to estimating what the average beta would be if the companies were financed entirely with equity capital. Equation (2) is used to estimate the unlevered beta for a firm or a group of similar-risk firms.[19]

$$\beta_U = \frac{\beta_{Measured}}{(1+(1-t)D/E)} \qquad (2)$$

Equation (2) indicates that an estimate of the unlevered beta (β_U) of a firm can be calculated by dividing the measured beta ($\beta_{Measured}$, e.g. the beta coefficient reported by investor services such as Value Line) by one plus the average debt-to-equity ratio, adjusted to account for taxes. The debt-to-equity ratio is measured using the average market value of the sample group's common equity capital. Once the unlevered beta for the firm (or, in this case, for the sample group of market-traded utility companies) is calculated, the beta coefficient is "re-levered" and adjusted to conform to the less leveraged capital structure of APS, which contains 50% common equity. The formula used to "re-lever" the utility betas is shown below.

$$\beta_{Relevered} = \beta_U (1+ (1-t)D/E) \qquad (3)$$

[19]Equation (1) is a version of the Hamada equation which combines the Miller-Modigliani theories regarding capital structure and the logic of the CAPM: Hamada, R.S., "Portfolio Analysis, Market equilibrium and Corporation Finance," *Journal of Finance*, March 1969, pp. 13-31.

Equation (3) states that the relevered beta equals the unlevered beta (β_U) multiplied times one plus the target debt-to-equity ratio (in this case APS's ratemaking capital structure—50% equity/50% debt), again adjusted for taxes.

Schedule 12 shows that, the average capital structure of the sample group of electric companies used to estimate the cost of equity capital in my direct testimony consists of 45.13% common equity and 54.69% fixed-income capital. That capital structure, adjusted to market levels by an average 1.69 market-to-book ratio and accounting for a 35% tax rate, produces an average value for (1-t)D/E in Equation (2) of 0.53.

Schedule 12 shows further that the measured (average Value Line) beta coefficient of the sample group of gas utility firms is 0.83, and the <u>unlevered</u> beta coefficient of those firms (i.e., what the average beta would be if those firms were financed entirely with common equity) is 0.54. When that beta is "relevered" using the methodology described above to conform to APS's ratemaking capital structure, the resulting average beta coefficient is 0.75, an decrease in beta of 0. 079 due to the sample group's lower average equity capitalization ["measured" beta of 0.83 vs. "relevered" beta of 0.751].

Finally, with the increase in beta determined, the CAPM can be used to estimate the impact of that adjustment on the cost of capital. A review of the CAPM equation (Equation (i) in Appendix D) indicates that the beta coefficient is multiplied by the market risk premium (r_m - r_f) as a step in the determination of the cost of capital. Therefore, it is possible to measure the impact of an adjustment to beta by multiplying the difference in the measured and relevered betas of the electric companies by the market risk premium.

As I noted in my discussion of the CAPM analysis in Appendix D, the long-term historical market risk premium provided by Ibbotson Associates' historical database is 5% to 6.6%. I also discuss the fact that the most recent research by Fama and French regarding the market risk premium indicates that the Ibbotson historical risk premium data overstate investor expectations, which are a return of 2.5% to 4.5% over the risk-free

rate of interest.[20] Ibbotson has also published a paper recently, which indicates that investors can expect returns in the future of from 4% to 6% above the risk-free.[21] Therefore, for purposes of this analysis, I will use a range of market risk premium from 4% to 6%.

As shown in Schedule 12, an decrease in the average beta coefficient of 0.079, multiplied by a market risk premium ranging from 4% to 6%, indicates an decrease in the cost of equity capital due to reduced leverage at APS of from 32 to 48 basis points (0.079 x 4%-6% = 0.317%-0.476%).

The mid-point of the cost of common equity for the electric utility sample group, presented previously is 9.50%. Although the equity return decrement indicated is slightly higher, recognizing the decrease in financial risk due to reduced leverage at APS, a cost of equity of 9.25% for ratemaking purposes is reasonable. That represents a decrease in the cost of equity for APS (with a 50% common equity ratio) of 25 basis points below the mid-point of a reasonable range for electric utility operations, which are capitalized on average with about 45% common equity.

It is important to emphasize here that if the Commission elects to utilize the Company's requested 54.5% common equity ratio for ratesetting purposes, rather than the 50% I recommend, the equity return decrement due to lower financial risk would have to be greater than the 25 basis points I recommend. If a "target" capital common equity ratio of 54.5% were substituted in Schedule 12, the "relevered" beta would be 0.72, rather than the 0.75 used in my analysis. Also the indicated reduction in the cost of equity would range from 0.45% to 0.68%. Those data indicate that if this Commission elects to set rates for APS using its requested capital structure, an equity return decrement of 50 basis points would be reasonable.

Q. DOES THAT 9.25% EQUITY COST ESTIMATE INCLUDE AN INCREMENT FOR

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[20] Fama, E., French, K., "The Equity Premium," *The Journal of Finance*, Vol. LVII, No. 2, April 2002, pp. 637-659.

[21] Ibbotson, R, Chen, P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

FLOTATION COSTS?

A. No, it does not.

Q. CAN YOU PLEASE EXPLAIN WHY AN EXPLICIT ADJUSTMENT TO THE COST OF EQUITY CAPITAL FOR FLOTATION COSTS IS UNNECESSARY?

A. An explicit adjustment to "account for" flotation costs is unnecessary for several reasons. First, it is often said that flotation costs associated with common stock issues are exactly like flotation costs associated with bonds. That is not a correct statement because bonds have a fixed cost and common stock does not. Moreover, even if it were true, the current relationship between the electric utility sample group's stock price and its book value would indicate a flotation cost reduction to the market-based cost of equity, not an increase.

When a bond is issued at a price that exceeds its face (book) value, and that difference between market price and the book value is greater than the flotation costs incurred during the issuance, the embedded cost of that debt (the cost to the company) is *lower* than the coupon rate of that debt.

In the current economic environment for the electric utility common stocks studied to determine the cost of equity in this proceeding, those stocks are selling at a market price 69% above book value. (Exhibit__(SGH-1), Schedule 4, p. 1) The difference between the market price of electric utility stock and book value dwarfs any issuance expense the companies might incur. Therefore, if common equity flotation costs were exactly like flotation costs with bonds, then, if an explicit adjustment to the cost of common equity were necessary, it should be downward, not upward.

Second, flotation cost adjustments are usually predicated on the prevention of the dilution of stockholder investment. However, the reduction of the book value of stockholder investment due to issuance expenses can occur only when the utility's stock is selling at a market price at to or below its book value. As noted, the companies under review are selling at a substantial premium to book value. Therefore, every time a new share of that stock is sold, existing shareholders realize an *increase* in the per share book

value of their investment. No dilution occurs, even without any explicit flotation cost allowance.

Third, the vast majority of the issuance expenses incurred in any public stock offering are "underwriter's fees" or "discounts". Underwriter's discounts are not out-of-pocket expenses for the issuing company. On a per share basis, they represent only the difference between the price the underwriter receives from the public and the price the utility receives from the underwriter for its stock. As a result, underwriter's fees are not an expense incurred by the issuing utility and recovery of such "costs" should not be included in rates.

In addition, the amount of the underwriter's fees are prominently displayed on the front page of every stock offering prospectus and, as a result, the investors who participate in those offerings (e.g., brokerage firms) are quite aware that a portion of the price they pay does not go to the company but goes, instead, to the underwriters. By electing to buy the stock with that understanding, those investors have effectively accounted for those issuance costs in their risk-return framework by paying the offering price. Therefore, they do not need any additional adjustments to the allowed return of the regulated firm to "account" for those costs.

Fourth, my DCF growth rate analysis includes an upward adjustment to equity capital costs which accounts for investor expectations regarding stock sales at market prices in excess of book value, and any further explicit adjustment for issuance expenses related to increases in stock outstanding is unnecessary.

Fifth, research has shown that a specific adjustment for issuance expenses is unnecessary[22]. There are other transaction costs which, when properly considered, eliminate the need for an explicit issuance expense adjustment to equity capital costs. The transaction cost that is improperly ignored by the advocates of issuance expense adjustments is brokerage fees. Issuance expenses occur with an initial issue of stock in a primary market offering. Brokerage fees occur in the much larger secondary market

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[22] "A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," Habr, D., National Regulatory Research Institute Quarterly Bulletin, January 1988, pp. 95-103.

where pre-existing shares are traded daily. Brokerage fees tend to increase the price of the stock to the investor to levels above that reported in the Wall Street Journal, i.e., the market price analysts use in a DCF analysis. Therefore, if brokerage fees were included in a DCF cost of capital estimate they would raise the effective market price, lower the dividend yield and lower the investors' required return. If one considers transaction costs that, supposedly, raise the required return (issuance expenses), then a symmetrical treatment would require that costs that lower the required return (brokerage fees) should also be considered. As shown by the research noted above, those transaction costs essentially offset each other and no specific equity capital cost adjustment is warranted.

Q. WHAT IS THE OVERALL COST OF CAPITAL FOR APS's INTEGRATED UTILITY OPERATIONS, BASED ON AN ALLOWED EQUITY RETURN OF 9.25%?

A. Schedule 13 attached to my testimony shows that an equity return of 9.25%, operating through an appropriate ratemaking capital structure of 50% equity and 50% debt, and the Company's requested embedded capital cost rates, produces an overall return of 7.33% for APS. Schedule 13 also shows that a 7.33% overall cost of capital affords the Company an opportunity to achieve a pre-tax interest coverage level of 3.85 times.

According to APS's 2005 S.E.C. Form 10-K (Exhibit 12), the pre-tax interest coverage over the past five years has averaged 2.94x and has ranged from 2.81x to 3.17x. The return I recommend would allow the Company the opportunity to improve its historical average interest coverage. Therefore, the equity return I recommend fulfills the legal requirement of Hope and Bluefield of providing the Company the opportunity to earn a return which is commensurate with the risk of the operation and serves to support and maintain the Company's ability to attract capital.

V. COMPANY COST OF CAPITAL TESTIMONY

Q. HOW HAS COMPANY WITNESS AVERA ESTIMATED THE COST OF EQUITY CAPITAL IN THIS PROCEEDING?

ARIZONA PUBLIC SERVICE COMPANY
LEVERAGE/BETA ADJUSTMENT TO THE COST OF EQUITY CAPITAL

COMPANY	COMMON EQUITY	FIXED INCOME CAPITAL	M/B RATIO	MKT. VALUE DEBT(1-t)/EQ.
Central Vermont P. S.	63.00%	37.00%	1.05	0.36
FirstEnergy Corp.	45.00%	55.00%	1.77	0.45
Green Mountain Power	56.00%	44.00%	1.30	0.39
Progress Energy	41.00%	59.00%	1.29	0.73
Ameren Corp.	50.00%	50.00%	1.58	0.41
Cleco Corporation	52.00%	48.00%	1.52	0.39
DPL, Inc.	35.00%	65.00%	4.51	0.27
Empire District Electric	46.00%	54.00%	1.37	0.56
Entergy Corp.	46.00%	54.00%	1.77	0.43
Hawaiian Electric	37.00%	63.00%	1.77	0.63
PNM Resources	38.00%	62.00%	1.31	0.81
Pinnacle West Capital	48.00%	52.00%	1.11	0.63
Unisource Energy	32.00%	68.00%	1.64	0.84
AVERAGES	45.31%	54.69%	1.69	0.53
TARGET CAP. STRUCTURE	50.00%	50.00%	1.69	**0.38**

AVERAGE (LEVERED) UTILITY BETA = 0.83

Beta (Unlevered) = Beta (Levered)/(1+D(1-t)/E)

Beta (Unlevered)= 0.83/(1+.53)= **0.54**

Beta (Relevered)= Beta (Unlevered)*(1+D(1-t)/E)

Beta (Relevered)= 0.54(1.38)= **0.75**

IMPACT ON COST OF EQUITY CAPITAL

	Measured Beta	0.830
	Relevered Beta	0.751
[1]	Diff. in Beta	0.079
[2]	Market Risk Premium (rm-rf) =	4% to 6%

Average Cost of equity impact = [1] x [2] = **0.32% to 0.48%**

ATTACHMENT D

Equity Risk Premiums (ERP): Determinants, Estimation and Implications

September 2008

(with an October update reflecting the market crisis)

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Equity Risk Premiums (ERP): Determinants, Estimation and Implications

Equity risk premiums are a central component of every risk and return model in finance and are a key input into estimating costs of equity and capital in both corporate finance and valuation. Given their importance, it is surprising how haphazard the estimation of equity risk premiums remains in practice. In the standard approach to estimating equity risk premiums, historical returns are used, with the difference in annual returns on stocks versus bonds over a long time period comprising the expected risk premium. We note the limitations of this approach, even in markets like the United States, which have long periods of historical data available, and its complete failure in emerging markets, where the historical data tends to be limited and volatile. We look at two other approaches to estimating equity risk premiums – the survey approach, where investors and managers ar asked to assess the risk premium and the implied approach, where a forward-looking estimate of the premium is estimated using either current equity prices or risk premiums in non-equity markets. We close the paper by examining why different approaches yield different values for the equity risk premium, and how to choose the "right" number to use in analysis. (In an addendum, we also look at equity risk premiums during the market crisis, starting on September 12, 2008 through October 16, 2008.)

This regression reinforces the view that equity risk premiums should not be constants but should be linked to the level of interest rates, at the minimum, and perhaps even to the slope of the yield curve. In Septermber 2008, for instance, when the 10-year treasury bond rate was 3.55% and the 6-month treasury bill rate was at 2.4%, the implied equity risk premium would have been computed as follows:

Implied ERP = 1.93% + 0.371 (3.55%) - .111 (3.55% – 2.4%) = 3.12%

This would have been well below the observed implied equity risk premium of about 4.54% and the average implied equity risk premium of 4% between 1960 and 2008.

While we have considered only interest rates in this analysis, it can be expanded to include other fundamental variables including measures of overall economic growth (such as expected growth in the GDP), exchange rates and even measures of risk aversion.

Implied Equity Risk Premiums during a Market Crisis – 9/15/08 to 10/16/08

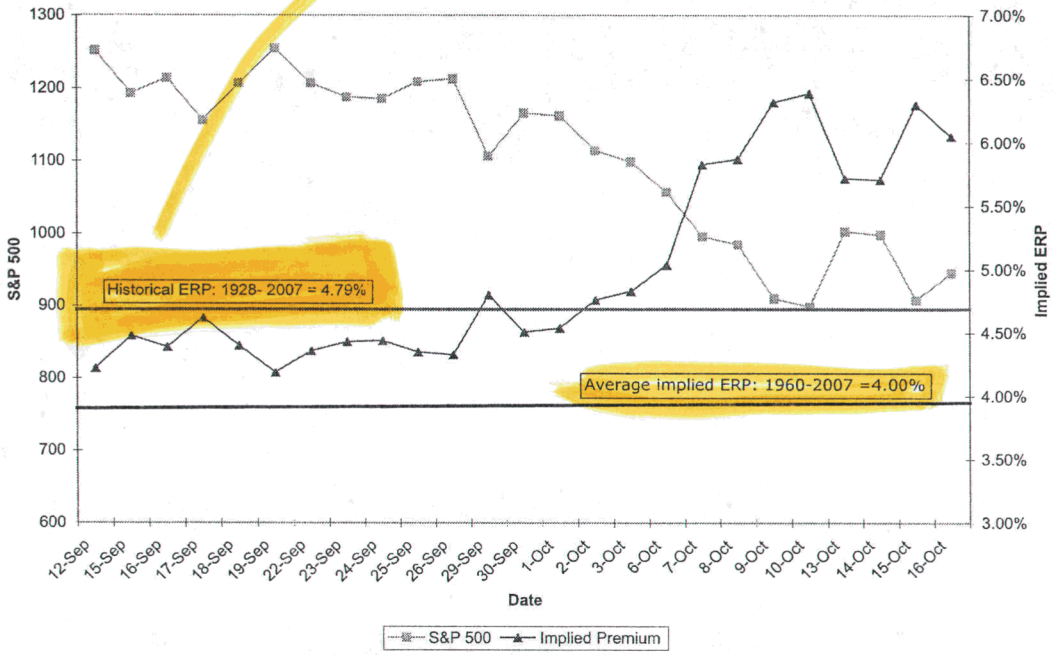
When we use historical risk premiums, we are, in effect, assuming that equity risk premiums do not change much over short periods and revert back over time to historical averages. This assumption was viewed as reasonable for mature equity markets like the United States, but was put under a severe test during the market crisis that unfolded with the fall of Lehman Brothers on September 15, and the subsequent collapse of equity markets, first in the US, and then globally.

Since implied equity risk premiums reflect the current level of the index, the 22 trading days between September 15, 2008, and October 16, 2008, offer us an unprecedented opportunity to observe how much the price charged for risk can change over short periods. In figure 7A, we depict the S&P 500 on one axis and the implied equity risk premium on the other. To estimate the latter, we used the level of the index and the treasury bond rate at the end of each day and used the total dollar dividends and buybacks over the trailing 12 months to compute the total yield. For example, the total dollar dividends and buybacks on the index for the trailing 12 months of 52.58 resulted in a dividend yield of 4.20% on September 12 (when the index closed at 1252) but jumped to 4.97% on October 6, when the index closed at 1057.[71]

[71] It is possible, and maybe even likely, that the banking crisis and resulting economic slowdown was leading some companies to reassess policies on buybacks. Alcoa, for instance, announced that it was terminating stock buybacks. However, other companies stepped up buybacks in response to lower stock prices. If the total cash return was dropping, as the market was, the implied equity risk premiums should be lower than the numbers that we have computed.

Equity Risk Prem.

Figure 7A: Implied Equity Risk Premium - 9/12- 10/16



In a period of a month, the implied equity risk premium rose from 4.20% on September 12 to 6.39% at the close of trading of October 10. Even more disconcertingly, there were wide swings in the equity risk premium within a day; in the last trading hour just on October 10, the implied equity risk premium ranged from a high of 6.6% to a low of 6.1%.

There are two ways in which we can view this volatility. One the one side, proponents of using historical averages (either of actual or implied premiums) will use the day-to-day volatility in market risk premiums to argue for the stability of historical averages. They are implicitly assuming that when the crisis passes, markets will return to the status quo. On the other hand, there will be many who point to the unprecedented jump in implied premiums over a four-week period and note the danger of sticking with a "fixed" premium. They will argue that there are sometimes structural shifts in markets, i.e. big events that change market risk premiums for long periods, and that we should be therefore modifying the risk premiums that we use in valuation as the market changes around us.

B.11

There is one final point to be made about the changes in risk premiums during this crisis. The volatility captured in figure 7A was not restricted to just the US equity markets. Global equity markets gyrated with and sometimes more than the US, default spreads widened considerably in corporate bond markets, commercial paper and LIBOR

rates soared while the 3-month treasury bill rate dropped close to zero and the implied volatility in option markets rose to levels never seen before. Gold surged but other commodities, such as oil and grains, dropped. Not only did we discover how intertwined equity markets are around the globe but also how markets for all risky assets are tied together. We will explicitly consider these linkages as we go through the rest of the paper.

Extensions of Implied Equity Risk Premium

The practice of backing out risk premiums from current prices and expected cashflows is a flexible one. It can be expanded into emerging markets to provide estimates of risk premiums that can replace the country risk premiums we developed in the last section. Within an equity market, it can be used to compute implied equity risk premiums for individual sectors or even classes of companies.

a. Other Equity Markets

The advantage of the implied premium approach is that it is market-driven and current, and does not require any historical data. Thus, it can be used to estimate implied equity premiums in any market, no matter how short its history, It is, however, bounded by whether the model used for the valuation is the right one and the availability and reliability of the inputs to that model. Earlier in this paper, we estimated country risk premiums for Brazil, using default spreads and equity market volatile. To provide a contrast, we estimated the implied equity risk premium for the Brazilian equity market in September 2008, from the following inputs.

- The index (Bovespa) was trading at 48,345 on September 9, 2008, and the dividend yield on the index over the previous 12 months was approximately 2%. While stock buybacks represented negligible cash flows, we did compute the FCFE for companies in the index, and the aggregate FCFE yield across the companies was 5.41%.
- Earnings in companies in the index are expected to grow 9% (in US dollar terms) over the next 5 years, and 3.80% (set equal to the treasury bond rate) thereafter.
- The riskfree rate is the US 10-year treasury bond rate of 3.80%.

The time line of cash flows is shown below:

$$48{,}345 = \frac{2{,}853}{(1+r)} + \frac{3{,}109}{(1+r)^2} + \frac{3{,}389}{(1+r)^3} + \frac{3{,}694}{(1+r)^4} + \frac{4{,}027}{(1+r)^5} + \frac{4{,}027(1.038)}{(r-.038)(1+r)^5}$$

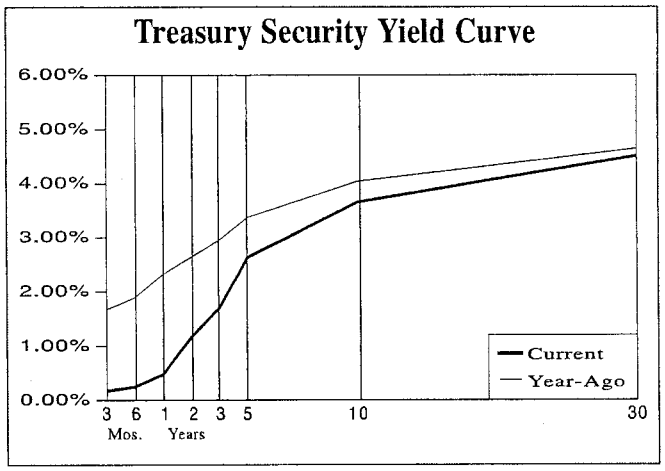
These inputs yield a required return on equity of 10.78%, which when compared to the treasury bond rate of 3.80% on that day results in an implied equity premium of 6.98%.

ATTACHMENT E

Selected Yields

	Recent (7/29/09)	3 Months Ago (4/29/09)	Year Ago (7/30/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.27	0.40	2.72
3-month LIBOR	0.49	1.03	2.80
Bank CDs			
6-month	0.56	0.79	1.59
1-year	0.83	0.98	2.11
5-year	1.90	1.93	4.16
U.S. Treasury Securities			
3-month	0.18	0.09	1.68
6-month	0.25	0.28	1.89
1-year	0.48	0.46	2.32
5-year	2.63	2.03	3.37
10-year	3.66	3.11	4.04
10-year (inflation-protected)	1.84	1.57	1.63
30-year	4.51	4.03	4.65
30-year Zero	4.61	4.05	4.69

	Recent (7/29/09)	3 Months Ago (4/29/09)	Year Ago (7/30/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.70	3.30	5.53
FHLMC 6.5% (Gold)	2.82	2.61	5.68
FNMA 6.5%	2.64	2.45	5.53
FNMA ARM	2.98	3.15	4.12
Corporate Bonds			
Financial (10-year) A	6.95	7.84	6.38
Industrial (25/30-year) A	6.02	6.41	6.32
Utility (25/30-year) A	5.79	6.33	6.31
Utility (25/30-year) Baa/BBB	7.14	7.58	6.78
Foreign Bonds (10-Year)			
Canada	3.53	3.08	3.82
Germany	3.42	3.13	4.42
Japan	1.38	1.42	1.53
United Kingdom	3.97	3.46	4.85
Preferred Stocks			
Utility A	5.71	7.53	6.12
Financial A	6.30	8.96	7.06
Financial Adjustable A	5.50	5.50	5.50



	Recent (7/29/09)	3 Months Ago (4/29/09)	Year Ago (7/30/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.69	4.57	4.77
25-Bond Index (Revs)	5.67	5.49	5.23
General Obligation Bonds (GOs)			
1-year Aaa	0.42	0.54	1.52
1-year A	1.12	1.04	1.62
5-year Aaa	1.77	1.80	3.08
5-year A	3.17	2.23	3.18
10-year Aaa	3.03	3.19	3.82
10-year A	4.55	3.55	4.02
25/30-year Aaa	4.72	4.67	4.78
25/30-year A	6.23	5.11	5.13
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.10	5.80	4.90
Electric AA	6.15	5.90	4.85
Housing AA	6.55	6.20	5.15
Hospital AA	6.50	6.15	5.25
Toll Road Aaa	6.10	5.95	4.85

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	7/15/09	7/1/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	743862	687737	56125	796972	764128	530566
Borrowed Reserves	387829	404097	-16268	482271	534612	488935
Net Free/Borrowed Reserves	356033	283640	72393	314701	229517	41631

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	7/13/09	7/6/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1657.7	1653.8	3.9	22.0%	7.0%	17.7%
M2 (M1+savings+small time deposits)	8333.7	8348.7	-15.0	3.4%	2.9%	8.0%

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ATTACHMENT F

INDUSTRY TIMELINESS: 45 (of 99)

Water Utility providers have fared pretty well of late, with increasingly favorable regulatory backing boosting revenues and driving strong bottom-line advances in the first quarter. Additional improvements are likely to evolve on the regulatory front and should enable most in this space to maintain their recent earnings momentum throughout the remainder of the year.

Nevertheless, these stocks, although up, have lost some of their luster since our April report. Indeed, the group, as a whole, has fallen from the upper echelon of the *Value Line Investment* universe for Timeliness, as the broader market showed some glimpses of rallying, and now sports an average rank.

But it still may be an area of interest for investors. Despite the recent spurts of price momentum, the market remains extremely volatile overall. The tough macroeconomic environment creates a difficult backdrop, which ought to favor industries that are perceived as relative safe havens, a trait typically exemplified by water utilities' historically steady dividend growth.

Financing issues raise some concerns, longer-term, however, and limit the group's 3- to 5-year appeal. In fact, not a single stock in this industry stands out for 3- to 5-year appreciation potential, as rising infrastructure costs threaten to erase the bulk of future profit advances.

A Swimmingly Refreshing Backdrop

There is no way around it, water is a necessity of life. As a result, water providers are vital as well, especially since reports show that the world's fresh water supply is limited and likely to dry up sooner than many were originally anticipating.

Meanwhile, many once protagonistic state regulatory commissions have changed their stances and have become more business friendly in recent times. This is extremely important as these regulatory authorities, which were put in place to help maintain a balance of power between customers and providers and to ensure fair business practices, are responsible for reviewing and ruling on general rate requests made by utilities to help recover costs. Decisions have been more timely and favorable of late and should only get better now that some states have enacted additional mechanisms that reduce outside influences (such as weather) on usage rates. Such initiatives are likely to enable companies to better recover unforeseen expenses, and thus deliver steadier financial results.

Oceans of Costs

Nevertheless, the water utilities is an increasingly capital intensive industry. Many infrastructures are outdated and will require heavy investment in order to make the necessary repairs. Greater EPA requirements only make things more difficult, as infrastructure costs are estimated at hundreds of millions of dollars over the next decade.

Cash is at a premium in this space, however, with most companies sporting highly leveraged balance sheets and nominal cash reserves. That said, debt and stock issuances have become, and are likely to remain, commonplace as providers struggle to foot the bill. Unfortunately, the increased costs associated with such financial undertakings, i.e. steeper interest rates and higher share counts, are likely to dilute share earnings growth as well as shareholder gains. Those able to raise capital may well benefit from the plethora of acquisition targets that have emerged.

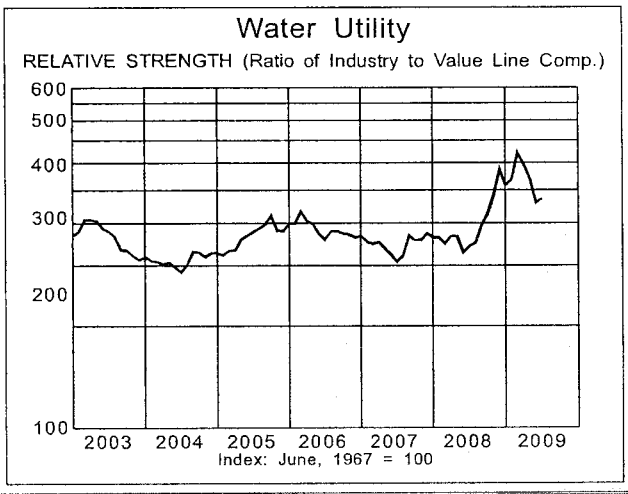
Conclusion

Although the stocks in this group do not stand out either for the coming six to 12 months or the 3- to 5-year pull, investors with a cautious bent may want to have a closer look. Water utilities will probably be a far more stable place to be if the market remains volatile, a fair bet given the glum economic indicators that have continued to come out. The current dividend yield of *California Water Services* is particularly interesting as is the future growth prospects of *Aqua America*, whose aggressive M&A strategy may well prove current projections modest. *American Water Works* is another interesting candidate, although its short trading history and parent company's control issues should scare off the risk averse. That said, as always, we advise investors to carefully review the pages of the individual stocks before making any financial commitments.

Andre J. Costanza

Composite Statistics: Water Utility Industry

2005	2006	2007	2008	2009	2010		12-14
1256.9	3454.1	3702.5	*3915*	*4250*	*4500*	Revenues ($mill)	*5425*
148.2	d5.8	d183.0	*420*	*435*	*475*	Net Profit ($mill)	*650*
40.5%	NMF	NMF	*37.0%*	*38.0%*	*39.0%*	Income Tax Rate	*40.0%*
1.1%	NMF	NMF	*8.0%*	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
50.4%	54.0%	51.0%	*55.0%*	*53.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
49.5%	45.9%	49.0%	*45.0%*	*47.0%*	*50.0%*	Common Equity Ratio	*50.0%*
3053.8	12113.9	12985.9	*13875*	*14600*	*15875*	Total Capital ($mill)	*18250*
4200.7	13308.3	14315.2	*15350*	*16100*	*16850*	Net Plant ($mill)	*19000*
6.3%	1.6%	.2%	*4.0%*	*4.0%*	*4.0%*	Return on Total Cap'l	*5.0%*
9.8%	NMF	NMF	*6.5%*	*6.5%*	*6.0%*	Return on Shr. Equity	*7.0%*
9.8%	NMF	NMF	*6.5%*	*6.5%*	*6.0%*	Return on Com Equity	*7.0%*
3.7%	NMF	NMF	*3.0%*	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
62%	NMF	NMF	*65%*	*65%*	*62%*	All Div'ds to Net Prof	*60%*
29.4	NMF	NMF		*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*20.0*
1.57	NMF	NMF				Relative P/E Ratio	*1.35*
2.1%	2.0%	2.3%				Avg Ann'l Div'd Yield	*2.3%*



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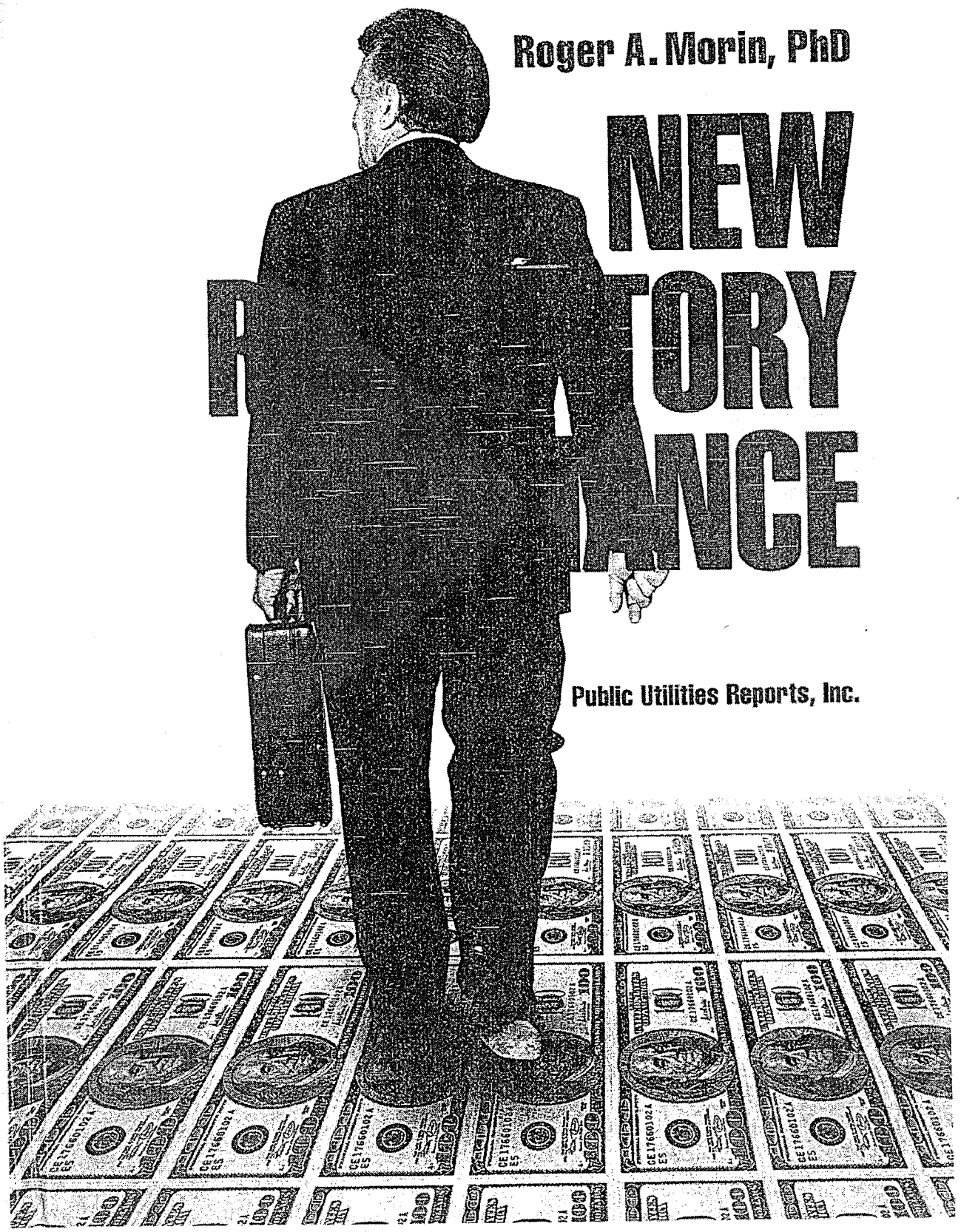
ATTACHMENT G

Roger A. Morin, PhD

NEW REGULATORY FINANCE

Public Utilities Reports, Inc.



DCF Growth Rate Check

As a reasonableness check on the DCF growth rate, the growth rate in dividends can be verified using the following relationship:[16]

Dividend Growth = Risk-free Return + Risk Premium − Dividend Yield

For example, let us say that the yield on Treasury bonds as a proxy for the risk-free return is 5%, the utility risk premium is 5.5% derived from a Capital Asset Pricing Model (CAPM) analysis discussed in earlier chapters, and the expected dividend yield for the utility industry is 4.5%. Substituting these values in the above relationship, we obtain a dividend growth expectation of 6.0% as follows:

Dividend Growth = 5.0% + 5.5% − 4.5% = 6.0%

9.6 Growth in the Non-Constant DCF Model

Although the constant growth DCF model does have a long history, analysts, practitioners, and academics have come to recognize that it is not applicable in many situations. A multiple-stage DCF model that better mirrors the pattern of future dividend growth is preferable. There is a growing consensus and ample empirical support that the best place to start is with security analysts' forecasts, that is, assume that dividend policy is relatively constant and use analyst forecasts of earnings growth as a proxy for dividend forecasts. The problem is that from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue into perpetuity. A transition must occur between the first stage of growth forecast by analysts for the first five years and the company's long-term sustainable growth rate. Accordingly, multiple-stage DCF models of this transition are available and were described in Chapter 8. It is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy.

A reasonable alternative to the constant growth DCF model is to use a multiple-stage DCF model that more appropriately captures the path of future dividend

[16] Equating the expected return from the standard DCF equation and the required return from the CAPM equation:

$$K = D_1/P + g = R_f + \text{Risk Premium}$$
$$K = D_1/P + g = R_f + \beta(R_m - R_f) \text{ from the CAPM}$$

Solving for g:

$$g = R_f + \beta(R_m - R_f) - D_1/P$$

MN 658.1522 K833V 2005

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R-34
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VALUATION

MEASURING AND MANAGING THE VALUE OF COMPANIES

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10

Estimating the Cost of Capital

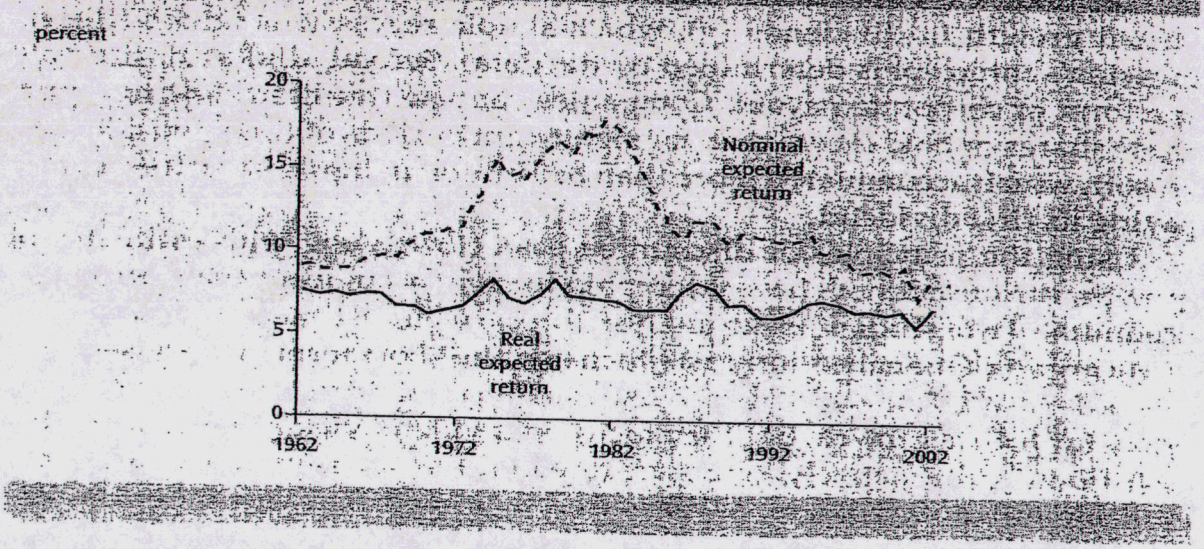
To value a company using enterprise DCF, we discount free cash flow by the weighted average cost of capital (WACC). The weighted average cost of capital represents the opportunity cost that investors face for investing their funds in one particular business instead of others with similar risk.

The most important principle underlying successful implementation of the cost of capital is consistency between the components of WACC and free cash flow. Since free cash flow is the cash flow available to all financial investors (debt, equity, and hybrid securities), the company's WACC must include the required return for each investor. In addition, the duration and risk of the financial securities used to estimate the WACC must match that of the free cash flow being discounted. To assure consistency, the cost of capital must meet several criteria:

- It must include the opportunity costs from *all* sources of capital—debt, equity, and so on—since free cash flow is available to all investors, who expect compensation for the risks they take.
- It must weight each security's required return by its target market-based weight, not by its historical book value.
- It must be computed after corporate taxes (since free cash flow is calculated in after-tax terms). Any financing-related tax shields not included in free cash flow must be incorporated into the cost of capital or valued separately (as done in the adjusted present value).
- It must be denominated in the same currency as free cash flow.
- It must be denominated in nominal terms when cash flows are stated in nominal terms.

For most companies, discounting free cash flow at the WACC is a simple, accurate, and robust method of corporate valuation. If, however, the

Exhibit 10.7 Real and Nominal Expected Market Returns



percent from 7.0 percent gives an estimate of the risk premium at just under 5 percent.

Although many in the finance profession disagree about how to measure the market risk premium, we believe 4.5 to 5.5 percent is an appropriate range. Historical estimates found in most textbooks (and locked in the mind of many), which often report numbers near 8 percent, are too high for valuation purposes because they compare the market risk premium versus short-term bonds, use only 75 years of data, and are biased by the historical strength of the U.S. market.

Estimating beta According to the CAPM, a stock's expected return is driven by beta, which measures how much the stock and market move together. Since beta cannot be observed directly, we must *estimate* its value. To do this, we first measure a raw beta using regression and then improve the estimate by using industry comparables and smoothing techniques. The most common regression used to estimate a company's raw beta is the market model:

$$R_i = \alpha + \beta R_m + \varepsilon$$

In the market model, the stock's return (not price) is regressed against the market's return.

In Exhibit 10.8, we plot 60 months of Home Depot stock returns versus S&P 500 returns between 1999 and 2003. The solid line represents the "best

ARIZONA WATER COMPANY

DOCKET NO. W-01445A-08-0440

SURREBUTTAL TESTIMONY ON RATE DESIGN

OF

JODI A. JERICH, DIRECTOR

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 12, 2009

EXHIBIT
R-35
ADMITTED

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INTRODUCTION

Q. Please state your name, occupation and business address for the record.

A. My name is Jodi Jerich. I am the Director of the Arizona Residential Utility Consumer Office (RUCO). My business address is 1110 W. Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Governor Brewer appointed me to serve as the Director of RUCO in February 2009. The State Senate found my qualifications met the statutory requirements found in Arizona Revised Statutes §40-462 and confirmed my appointment. As Director, I oversee and approve all testimony and briefs filed by RUCO. In consultation with my staff, I direct the public policy decisions of the office.

From 2003 through 2005, I was employed at the Arizona Corporation Commission as the Policy Advisor to Corporation Commissioner Mike Gleason. In that role, I advised the Commissioner on matters coming before the Commission including water utility rate cases. I was actively involved in the utility policy-making decisions of that Commissioner's office.

Except for the time I was employed by the Commission, from 1997 through 2008, I was employed at the Arizona House of Representatives. I held several

positions during my tenure, eventually becoming Chief of Staff and Counsel to the Majority Caucus. Relevant to the question at hand, I advised Legislators on matters involving water, energy, Commission jurisdiction and utility security.

In 2006, when Governor Janet Napolitano appointed Barry Wong to fill the Commission seat vacated by Commissioner Marc Spitzer's appointment to the Federal Energy Regulatory Commission (FERC), I took a leave of absence from the Legislature for a short time in order to assist Commissioner Wong establish his office.

Finally, I am a Phi Beta Kappa graduate of Indiana University. I also have a juris doctorate degree from Indiana University and am a member of the Arizona and Tennessee bars.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain RUCO's position on rate consolidation in this docket.

RATE CONSOLIDATION

Q. What is "rate consolidation"?

A. Rate consolidation is also commonly known as "single tariff pricing". In addition, the terms "uniform rates", "standard tariff rates", "unified rates"

and "rate equalization" are sometimes used. My testimony will refer to this concept as rate consolidation.

Rate consolidation is the use of a unified rate structure for multiple water utility systems that are owned and operated by a single utility, but that may not be contiguous or physically interconnected. Through rate consolidation, all customers of the utility pay the same rate for service, even though the individual systems providing service may vary in terms of the number of customers served, operating characteristics and stand alone costs.

Q. What is RUCO's position on rate consolidation in this docket?

A. RUCO believes that rate consolidation is a matter of public policy to be determined by the Corporation Commission. There are several public policy reasons to oppose rate consolidation. On the other hand, there are other public policy considerations to support rate consolidation. My testimony will outline the general reasons for and against rate consolidation. As it has in the past, RUCO continues to contend that separate rates for separate systems respect the principle of traditional cost of service ratemaking and ensure that those who use the utility services pay for them. However, if the Commission were to find that rate consolidation is in the public interest, then RUCO would not object to rate consolidation for all 17 systems ***in this particular docket as shown as Option F in Exhibit B***. With that said, RUCO would oppose any routine approval of rate consolidation proposals in the future and would

encourage the Commission to review rate consolidation proposals on a case-by-case basis.

Q. Why has RUCO opposed consolidation in the past?

A. Previously, rate consolidation proposals have been limited to the consolidation of two systems – typically a large system and a small one. In 2004, both RUCO and Staff opposed Arizona Water's request to consolidate the commodity rates for the Apache Junction and Superior systems. Apache Junction had 16,093 customers and Superior had 1,288 customers. RUCO and Staff opposed this consolidation because of the traditional ratemaking principle that individual system rates should reflect their specific system costs (Decision No. 66849 at p. 28).

Q. Has the Commission rejected rate consolidation proposals in the past?

A. Yes. For example, the Commission rejected Arizona Water's proposal to consolidate the base rate and ACRM for the Sedona and Rimrock systems in its Northern Group (Decision No. 66400). Furthermore, the Commission has rejected other Arizona Water rate consolidation proposals. (See Decision No. 58120 at 33-34 and Decision No. 64282 at 20-21.)

Q. Has the Commission approved rate consolidation proposals in the past?

A. Yes. The Commission has approved Arizona Water Company's proposals for consolidation for ratemaking purposes of the Sedona and Valley Vista systems as well as the consolidation of the Apache Junction and Superior systems.

In Decision No. 66849, over the opposition of Staff and RUCO, the Commission approved the consolidation of the Apache Junction and Superior systems stating:

> "Although Staff and RUCO point out that the Company's Northern Group consolidation recommendation was recently denied, the request in this proceeding is distinguishable. First, unlike the situation in the Northern Group case, the Superior and Apache Junction systems are already contiguous. Further, the backbone transmission facilities needed to serve a development approximately four miles from the Superior system well fields are already under construction, and full interconnection with Superior will be completed in less than two years. Thus, the interconnection of systems is not speculative but is imminent. Given these differences from the Northern Group proceeding, we believe it is appropriate to allow the first step of consolidation at this time in order to recognize the interconnection of the systems and to minimize the "rate shock" that may otherwise be experienced by customers in the Superior system." (Decision No. 66849 at 28.)[1]

From past history, it appears that the Commission has been most persuaded to approve rate consolidation when two systems are either

[1] It is RUCO's understanding that the Company did not interconnect these two systems.

being physically interconnected or close enough geographically such that interconnection has been contemplated.

Q. Does this history suggest that the Commission will look at rate consolidation on a case-by-case basis?

A. Yes. According to a 1999 joint publication by the U.S. Environmental Protection Agency (EPA) and the National Association of Regulatory Utility Commissioners (NARUC), the Arizona Corporation Commission is one of 22 state commissions that have allowed regulated water utilities to implement single tariff pricing.[2] As discussed above, Arizona has approved single tariff pricing on a case-by-case basis.

A copy of the EPA-NARUC publication is attached as Exhibit A.

Q. What are the arguments in favor of rate consolidation?

A. The EPA-NARUC publication offers several arguments in support of rate consolidation. RUCO lists the arguments it finds most persuasive.

1. Mitigates rate shock to utility customers.
2. Lowers administrative costs to the utilities.
3. Provides incentives for utility regionalization and consolidation.
4. Lowers administrative cost to the commission.

[2] "Consolidated Water Rates: Issues and Practices in Single-Tariff Pricing" EPA 816-R-99-009, September 1999, at p. 52 and Table E1.

5. Encourages larger utility companies to acquire small, struggling utilities.

Q. Does RUCO find any of these arguments persuasive?

A. Yes. RUCO finds rate consolidation a worthy public policy consideration in this case for all of the above reasons. RUCO is particularly persuaded by the fact that consolidated rates make it much easier for a large water utility to acquire a small, struggling water company.

According to the Commission's website, there are 288 Commission regulated water companies in Arizona. The majority of them are Class C, D, and E companies. Many of these companies are located in rural, remote areas.

"Larger utilities often are reluctant to consider acquiring smaller, nonviable systems unless reliable means of cost recovery can be identified and secured. An acquisition candidate often presents substantial infrastructure needs but its service community lacks the ability to pay for improvements through higher rates."[3] A consolidated rate schedule is "an incentive for larger water utilities to acquire small water systems that lack capacity because it makes it possible to spread costs over a larger service population and maintain more stable and affordable rates for customers of some smaller and more expensive systems."[4]

[3] Id. at 28.
[4] Id. at vii.

For example, in 2006, the Commission approved the sale of seven (7) small water systems (known collectively as "the McLain systems") to Algonquin Water Resource subsidiaries, Northern Sunrise and Southern Sunrise Water Companies. (Decision No. 68826). While the Order found the McLain systems had a combined fair value rate base of $696,752.14, the Commission recognized the need to make capital improvements totaling $802,100.00, along with approving an acquisition fee of $300,000.

In an earlier Order to determine the rate base value of the McLain systems, the Commission noted that the systems were in "serious disrepair" and posed a "serious safety hazard". The systems were "plagued by numerous outages caused by well failures, line breaks, power outages, possible sabotage and demand exceeding supply. None of the McLain Water Systems are chlorinated, which is serious because the poor condition of the systems makes them prone to microbial contamination". (Decision No. 68412 at pp. 4-5). The Commission had already appointed an interim manager (Decision No. 66241) and exerted its regulatory authority to find a willing buyer to take over these systems. Algonquin was the only bidder for the systems.

The McLain system failure provides an important lesson. Many Arizonans—particularly those in rural Arizona—receive water utility service from small water companies. Small utilities face greater obstacles in the provision of water delivery service than their larger counterparts. Since they have fewer customers to spread costs, they have unique pressures to maintain capital

and operating costs while providing quality water service. Smaller water systems are at risk of underperformance primarily because they simply are not large enough to achieve economies of scale. Additionally, smaller companies may not be able to attract equity investors or obtain debt on favorable terms as easily as large utilities. It is difficult for small companies to take advantage of any economies of scale and pass along the savings to their customers. Yet, customers of small water companies deserve the same quality of service that customers of large, more sophisticated water companies receive.

If full rate consolidation were to become a possible option in cases where the acquisition of a struggling, non-compliant water utility is in the public interest, then RUCO believes it is more likely that more companies would be willing to purchase that utility.

Again, RUCO believes all residential ratepayers throughout Arizona deserve clean, safe and reliable drinking water. However, the reality is that several small, rural water utilities are unable to provide it. According to the Arizona Department of Environmental Quality ("ADEQ"), numerous small water companies have struggled to meet water quality standards. For example, ADEQ currently has an enforcement case pending against McNeal Water (25 customers). East Slope (784 customers), Indiada (54 customers) and Antelope Run (140 customers) currently have outstanding Notices of Violations ("NOVs"). Furthermore, the following Commission-regulated

utilities have either outstanding NOVs and have recently resolved an NOV: Winchester Heights (129 customers), Monte Vista (40 customers), Sonoita Valley (40 customers), and Ashcreek (91 customers and currently operated by an interim manager).

Q. What are the arguments in opposition to rate consolidation?

A. The EPA-NARUC publication also offers several arguments in opposition to rate consolidation. RUCO lists the arguments it finds most persuasive.

1. Conflicts with cost of service principles.
2. Provides subsidies to some high cost customers at the expense of other customers.
3. Distorts price signals.
4. Discourages water conservation.

Q. Are these important considerations for RUCO?

A. Absolutely. All four of these arguments are strong reasons to reject a proposal to consolidate rates. However, RUCO contends that it has identified a rate consolidation design (Option F) that mitigates these concerns to some degree.

Q. Explain the rate design options considered by RUCO.

A. RUCO identified six (6) rate design options using the revenue requirements it filed in its surrebuttal testimony. I have attached these options as Exhibit B.

RUCO decided not to limit its consideration of rate consolidation solely to the proposal submitted by the Company. Instead, RUCO reviewed several different rate consolidation options. By reviewing Exhibit B, it will be readily apparent why RUCO prefers Option F over other rate consolidation proposals.

Q. Before going into detail for all the rate consolidation options, please explain Option F and why RUCO prefers Option F.

A. Option F ensures that no system receives more than a $5.00 increase for its average residential ratepayer. This Option consolidates all 17 systems into a single base rate. However, each system retains its own individual commodity rates. No system would incur more than a $5.00/month increase in rates for the average residential ratepayer.

There are several reasons why RUCO prefers Option F. First, this proposal consolidates <u>all</u> 17 systems into a single base rate. Instead of matching up one large system for the perpetual subsidization of a smaller system, costs are spread to all ratepayers. This is the only practical method where a large system would realize any significant financial benefit from consolidation. When consolidation is limited to pairing a large system with a small one, the larger system always subsidizes the majority of the smaller system's costs. The smaller system would only cover a minor portion of the larger system's

costs.[5] Second, under Option F, no system would realize more than a $5.00 rate increase. Under all other proposals, some systems would receive very large increases, while some others would see very large decreases. Option F has the most narrow band width between the dollar amounts for systems that get a decrease and those that receive an increase. Third, Option F retains individual system commodity rates. This requires the Company to keep track of expenses on a per system basis and allows Commission Staff a morethorough review of the Company's books. Fourth, separate commodity rates are based on cost of service. Option F preserves some integrity for this ratemaking principle. Finally, Option F's individual commodity rates mitigates the concern that rate consolidation would discourage water conservation.

Q. Please review the six (6) rate design options.

A. ***Option A*** ***<u>Maintain Separate Systems</u>***

Option A is a traditional rate design with ***no consolidation***. This option adheres to the cost of service principle and the plan encourages water conservation, but Miami and Stanfield will experience rate shock with 40.55% and 102.19% average increases, respectively.

[5] For illustrative purposes, System A has 90 customers and is consolidated with System B which as 10 customers. In Year 1, System B incurs $1,000 of capital costs. Under consolidation, System A picks up 90% of these costs while the System B covers only 10%. In Year 3 when System A needs $9,000 of capital improvements, System A still covers 90% of its own expenses while System B only picks up 10%. With more systems consolidated, costs are further spread and the percentage of costs subsidized is reduced.

Each system has its own base rate and commodity charges based on the cost of service for that individual system.

Option B ***Company Proposed Consolidation***

This is the consolidation option proposed by the Company. It consolidates some of the systems and leaves others alone. The Company proposes to consolidate several systems – typically matching a large system with a small one. Some of the consolidated systems are fully consolidated and others only have a consolidated base rate and separate commodity rates. This proposal may avoid rate shock, but the pairing of larger systems with smaller systems will result in cross subsidization of smaller systems in a way which is inequitable for the larger system. There are more equitable options to consider.

Option C ***Full Consolidation by Group***

The Company divides its 17 systems into three Groups: The Northern Group, the Eastern Group and the Western Group. RUCO designed rates for the consolidation of the 17 systems into three groups. All the systems in the Northern Group would be combined into one rate design and the same for the Eastern Group and the Western Group. This option does not address rate shock to Winkelman and Sierra Vista.

Option D ***Full Consolidation of all 17 Systems***

Option D consolidates all 17 systems into a single rate design. All systems would have the same base rate ***and*** the same commodity rates. This option has the same problems as Options B and C. The option does not have to address rate shock to Winkelman.

Option E ***Fully Consolidated Base Rate with Individual Commodity Rates***

Option E is a variation of Option D. All 17 systems would have the same base rate ***but have their own commodity rates***. Retention of commodity rates encourages water conservation, sends the appropriate price signals for proper water conservation and honors cost of service principles. However, this option does not avoid rate shock to Miami and Stanfield.

Option F ***Modified Option E with an adjusted base rate to ensure no system incurs more than a $5.00 increase.***

Option F is Option E with one modification to address issues of rate shock and provides greater rate stability. The modification in Option F reduces the revenue requirement for those systems that would have experienced an increase larger than $5.00 under Option E by adjusting the base rate for all systems. By doing so, no system has more than a $5.00 increase for the average residential customer. This also has the effect of diminishing the reductions some systems would have experienced under Option E. In effect,

it narrows the band of change from the present rates and provides additional support for the argument that rate consolidation provides rate stability.

Q. Why doesn't RUCO support the rate consolidation plan proposed by the Company (Option B)?

A. The Company's proposal results in inequitable unilateral subsidization of smaller systems by larger systems. RUCO finds that this type of rate consolidation is a one way street always benefitting one system and always burdening the other system.

As in the past, the Company's current proposal matches a large system with one or two small systems.[6] The purpose of this type of consolidation is to mitigate the rate increase of the smaller system by having the larger system pay more than its fair share.

One of the reasons FULL rate consolidation appeals to RUCO in this docket is that it allows everyone's costs to be spread across all the systems. While consolidation in this rate case will initially have some systems pay some costs for other systems, over time those systems that pick up some costs from other systems will receive relief in the future when other systems pick up some of their costs. In the Company's proposal, there is no way that the small

[6] The Company matches Superstition (18,257 customers) with Miami (2,820 customers) and Casa Grande (20,642 customers) with Stanfield (179) and Coolidge (4,229). Sedona (5,154) will subsidize Pinewood (2,862) and Rimrock (1,230). The Company does propose to consolidate the two similarly sized systems of Bisbee (3,085) and Sierra Vista (2,664).

systems will provide any meaningful rate benefit for their larger "host" system in the future. The larger system will always be covering for the smaller system. This perpetual inequity requires RUCO to oppose the Company's limited rate consolidation proposal.

For example (as shown in Exhibit B), under the traditional cost of service rate design of Option A (no consolidation), the Miami system is to receive a $13.89 (40.55%) ***increase*** to cover its expenses. However, under the Company's proposal to consolidate Miami with Superstition as shown in Option B, Miami would enjoy a $2.21 (6.44%) ***decrease***. This cost shift goes too far. It's one consideration if the purpose of rate consolidation is to ***mitigate*** rate increases for smaller systems. It's another concern entirely to ***eliminate*** any responsibility for that system to cover its own costs. Meanwhile, Superstition's rate increase jumps from $0.12 (0.36%) without consolidation to $2.24 (6.63%) under the Company's proposed consolidation plan. Miami's 2,820 customers will always benefit from merging rates with Superstition's 18,257 customers. And Superstition would never benefit in any meaningful way from this plan in the future because Miami is simply too small to absorb any substantial portion of Superstition's costs.

The Company also proposes to consolidate Casa Grande (29,642), Coolidge (4,229) and Stanfield (179). Without rate consolidation, Stanfield ratepayers would be hit with a $43.53 (102.19%) ***increase***. The Company's consolidation proposal does far more than merely mitigate this increase. Under the

Company's proposal, Stanfield would see a $7.37 (17.30%) ***decrease***. These costs would be picked up primarily by Coolidge, which would see its $0.78 (3.03%) rate ***decrease*** turn into a $2.55 (9.96%) rate ***increase***. Finally, the Sedona/Rimrock/Pinewood proposal would see Rimrock swing from a $5.36 (11.54%) ***increase*** to a $5.59 (12.04%) ***decrease***. Again, rate consolidation should not eliminate all cost recovery obligations for a system.

Q. What are some of the considerations of Option C, which consolidates the 17 systems into 3 consolidated rates groups?

A. There are two primary considerations for rate consolidation by Group. First, the consolidated systems are geographically close. From past Commission decisions, geographic proximity has, at times, been a factor weighing in favor of consolidation. Furthermore, Company resources such as employees, maintenance equipment, fleet vehicles and office space are shared by these systems. Second, a future rate case would not require the Company to file an application on a company-wide basis. As in the past, the Company could come in for a rate application for a single consolidated Group. This may be less of a strain on resources for both the Company and Staff compared to a company-wide rate case. Nonetheless, RUCO finds Option F a better rate design than Option C in this case because it spreads the costs to all the ratepayers company-wide and it mitigates the impact of rate increases, encourages conservation and adheres, in part, to the cost of service principle.

Q. What are some of the considerations of full rate consolidation of all 17 systems (Option D)?

A. Full rate consolidation for the entire company allows costs to be spread over a larger base of customers. This minimizes the rate impact for those customers who would have to bear the entire cost of expenses attributed to their system.

Furthermore, full rate consolidation eliminates the need to identify revenue requirements for each system. This results in administrative efficiency. As the Massachusetts Department of Public Utilities stated, "The Department has found that single tariff pricing provides benefits to customers associated with operational and functional consolidation. In addition, single tariff pricing is consistent with the goal of administrative simplicity." (DPU 86-27-A at 77-85; DPU 17885, at 5.).

In order to consolidate all systems, some customers will pay more and some will pay less. However, systems that picked up other systems' costs will receive a benefit from those other systems in the future because their costs will be spread across other systems.

> "A leading argument for single-tariff pricing made by multi-system water utilities is that each individual system eventually will require an infusion of capital for renovations and improvements; only the timing varies. Equalizing rates smoothes the effect of discrete cost spikes across systems and over time, much like insurance pooling."[7]

In RUCO's opinion, a favorable rate consolidation proposal is one that has the least detrimental effect to the systems that are picking up costs for other systems at the initial stage of consolidation. Over time, rates are stabilized and increases are minimized by spreading the costs over all systems.

However, the most obvious cost shift happens in the initial rate case when rate design shifts from cost of service to consolidated rates. Any effort to mitigate the impact of that shift is in the public interest. As stated earlier, Option F has the smallest dollar amount variation between those systems that receive a rate increase (no more than $5.00) and those that receive a rate decrease (no more than $7.18). Under Option D's full consolidation, the swing goes from a rate increase of $13.62 to a rate decrease of $18.07.

Q. What are some concerns RUCO has with full rate consolidation (Option D)?

A. RUCO has two primary concerns. First, full rate consolidation eliminates the need to maintain books for individual systems. This could lead to the Company over-building a system or not maintaining prudent costs controls

[7] Id. at 4.

since the widespread sharing of these costs minimizes the rate increase. This may incent a Company to unnecessarily inflate its rate base.

> "If rates were to be consolidated, there would be no reason to maintain separate books and records for each of the [systems]...However, this loss of operation and financial data would destroy the ability to evaluate the effectiveness and efficiency of the Company's operation of the [systems]. As a result, the [public utility commission] would lose its ability to exercise regulatory oversight and control as it pertains to these systems."[8]

If the Commission were to find that full rate consolidation is in the public interest, it could still order the Company to maintain system-specific bookkeeping. This would be helpful for Staff, RUCO and others to determine if costs were appropriately and prudently incurred in future rate cases.

A second concern of full rate consolidation is that this option can send improper price signals to certain systems. Rate consolidation is arguably "at odds with water conservation."[9] Water is not the same everywhere in the state. Different systems have different challenges with water quality or water quantity issues. For example, under the full rate consolidation of Option D, the Pinewood system would realize a 20.02% ***decrease*** in rates. Yet, this system, like some others, has water delivery difficulties at times due to

[8] Id. at 8 citing Ernest Harwig, Direct Testimony before the New Hampshire Public Utilities Commission in DR 97-058, Pennichuck Water Works, Inc. (1997).
[9] Id. at 5.

inadequate water supplies. Full rate consolidation ignores the harsh reality of the difficulty of delivery of adequate and safe water in certain areas in Arizona.

These two concerns are important reasons why RUCO believes that the consolidation proposal in Option F is the preferred rate consolidation plan. Since Option F retains individual system commodity charges, the Company must continue to maintain books for each individual system. Second, the individual commodity rates maintain the integrity of price signals for proper water conservation. In addition to these primary concerns, Option D also does not address the rate shock to Winkelman.

Q. Discuss Option E.

A. Option E provides a single base rate for all 17 systems, but each system has its own commodity rates based on its cost of service.

As in Option D, for future rate cases, the Company would have to come in on a company-wide basis. Since each system has its own commodity rates, the Company and Staff will still have to identify a revenue requirement for each system. However, this option recognizes the importance of each system having its unique water acquisition needs. It is more challenging to deliver

water to customers in Pinewood than it is in Casa Grande. Some systems require more wells or deeper wells for the same output. In addition to water ***delivery and quantity*** issues, systems may have water ***quality*** issues that other systems do not experience. System specific commodity rates help send appropriate price signals to customers that water delivery in certain areas is more difficult than in other areas. This option also preserves some notion of cost of service on a system–by-system basis.

Q. Explain Option F and why it is RUCO's preferred consolidated rate design.

A. Should the Commission decide that consolidation in this case is in the public interest, adoption of Option F is RUCO's preferred plan for rate consolidation. It is a modified version of Option E, and its purpose was to limit the amount of the rate increase to no more than $5.00 and to narrow the band between the systems with decreased rates for the average residential user and the systems with increased rates for the average residential user.

There are several reasons why RUCO encourages the Commission to adopt the rate consolidation plan of Option F if it does decide to consolidate rates in this docket.

First, Option F was intentionally designed so that no system would experience more than a $5.00 rate increase for the average residential user. This Option avoids rate shock better than any of the other proposals.

Second, Option F consolidates all base rates but maintains separate commodity rates. Those who, like RUCO, are uncomfortable with completely leaving traditional cost of service principles will take some comfort that these principles are preserved through the commodity rates.

Third, separate commodity rates also send the proper price signals for water conservation.

Fourth, Option F would require the Company to maintain separate books for each system to ensure that Staff, RUCO and others can review whether the Company is prudently incurring costs.

Q. Does this conclude your testimony?

A. Yes.

Rate Design Surrebuttal Testimony of Jodi A. Jerich
Arizona Water Company
Docket N. W-01445A-08-0440

EXHIBIT A

United States
Environmental Protection
Agency

Office of Water
Washington, DC 20460

EPA
September 1999

CONSOLIDATED WATER RATES: Issues and Practices in Single-Tariff Pricing

September 1999

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Utility Commissioners

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Acknowledgment and Disclaimer

This document is a collaborative effort of the United States Environmental Protection Agency (USEPA) and the National Association of Regulatory Utilities Commissioners (NARUC). USEPA is responsible for the implementation of Safe Drinking Water Act provisions. NARUC represents state public utility commissions that have jurisdiction for investor-owned and other water utilities.

This report does not constitute polices, positions, or views of the USEPA, NARUC, or NARUC-member commissions.

The report was prepared by Janice A. Beecher, Ph.D., Beecher Policy Research, Inc., who conducted an independent survey of commission staff members in 1996 on behalf of the staff of the Florida Public Service Commission and subsequent verifications and updates through contacts with the commissions.

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Consolidated Water Rates: Summary

Purpose

Consolidated rates or single-tariff pricing is the use of a unified rate structure for multiple water (or other) utility systems that are owned and operated by a single utility, but that may or may not be contiguous or physically interconnected. The purpose of this report is to provide policymakers and other stakeholders with an overview of consolidated ratemaking and an appreciation of the complex trade-offs involve in its implementation.

The report provides a review of historical, theoretical, and practical issues related to consolidated ratemaking, implementation data, and key decisions by the state public utility commissions. A detailed survey of state public utility commission staff regarding single-tariff pricing is presented. General commission policies are summarized, along with citations of specific regulatory decisions concerning single-tariff pricing.

How Consolidated Pricing Works

Under consolidated pricing, all customers of the corporate utility pay the same rate for the same service, even though the individual systems providing service may vary in terms of operating characteristics and stand-alone costs. In many respects, consolidated rates are the conceptual opposite of "zonal" or spatially differentiated rates.

Single-tariff pricing is used by many investor-owned water utilities, with the approval of state regulators, but it also can be implemented by publicly owned utilities. Single-tariff pricing can be an incentive for larger water utilities to acquire small water systems that lack capacity because it makes it possible to spread costs over a larger service population and maintain more stable and affordable rates for customers of some smaller and more expensive systems. Single-tariff pricing can be used by publicly owned or nonprofit water utilities that operate satellite systems, but few examples are readily available.

Unfortunately, the literature on utility ratemaking, which leans heavily toward the conditions and experiences of the energy and telecommunications industries, yields little theoretical insight or empirical evidence on the implications of single-tariff pricing. Much of the understanding of this issue is derived from case-specific regulatory proceedings. However, an analysis of historical and theoretical perspectives suggests that single-tariff pricing is not necessarily inconsistent with the prevailing principles of ratemaking.

The Tradeoffs

Single-tariff pricing is a provocative issue precisely because of the tradeoffs involved in its application, including possible tradeoffs among different types of efficiency. Single-tariff pricing might lessen some kinds of efficiency (such as those related to spatial allocation of costs and price signals to customers), while improving other kinds of

efficiency (such as those related to management and innovation). Of particular importance, but hardest to gauge, is whether single-tariff pricing and related restructuring can lead to long-run efficiency improvements in the water industry. Water utilities and policymakers must consider and weigh the evidence and trade-offs prior to implementing or approving single-tariff pricing.

A variety of theoretical and practical arguments in favor and against the use of single-tariff pricing can be made. Single-tariff pricing tends to stabilize rates and revenues, mitigate rate shock, and make rates more affordable for the customers of the smallest and more expensive systems. While achieving certain capacity-development, affordability, and operation efficiency goals, however, single-tariff pricing also might trade a degree of economic efficiency by ignoring spatial differences in costs and diluting price signals. A 1996 survey of commission staff members identified several arguments in favor of and against single-tariff pricing were identified.

Summary of Select Arguments in Favor and Against Single-Tariff Pricing

Select Arguments in Favor of Single-Tariff Pricing	Select Arguments Against Single-Tariff Pricing
❒ Mitigates rate shock to utility customers (17)	❒ Conflicts with cost-of-service principles (14)
❒ Lowers administrative costs to the utilities (16)	❒ Provides subsidies to high-cost customers (12)
❒ Provides incentives for utility regionalization and consolidation (15)	❒ Not acceptable to all affected customers (10)
❒ Physical interconnection is not considered a prerequisite (13)	❒ Considered inappropriate without physical interconnection (8)
❒ Addresses small-system viability issues (13)	❒ Distorts price signals to customers (7)
❒ Improves service affordability for customers (12)	❒ Fails to account for variations in customer contributions (6)
❒ Provides ratemaking treatment similar to that for other utilities (10)	❒ Justification has not been adequate in a specific case (or cases) (6)
❒ Facilitates compliance with drinking water standards (9)	❒ Discourages efficient water use and conservation (4)
❒ Overall benefits outweigh overall costs (9)	❒ Encourages growth and development in high-cost areas (4)
❒ Promotes universal service for utility customers (8)	❒ Undermines economic efficiency (3)
❒ Lowers administrative cost to the commission (8)	❒ Provides unnecessary incentives to utilities (2)
❒ Promotes ratepayer equity on a regional basis (6)	❒ Not acceptable to other agencies or governments (2)
❒ Encourages investment in the water supply infrastructure (5)	❒ Insufficient statutory or regulatory basis or precedents (2)
❒ Promotes regional economic development (3)	❒ Overall costs outweigh overall benefits (2)
❒ Encourages further private involvement in the water sector (2)	❒ Encourages overinvestment in infrastructure (1)
❒ Other: Can be consistent with cost-of-service principles (1) and found to be in the public interest (1)	

Source: Author's construct. See Tables E3 and E4. Numbers in parentheses represent number of mentions (out of 21 applicable survey responses).

efficiency (such as those related to management and innovation). Of particular importance, but hardest to gauge, is whether single-tariff pricing and related restructuring can lead to long-run efficiency improvements in the water industry. Water utilities and policymakers must consider and weigh the evidence and trade-offs prior to implementing or approving single-tariff pricing.

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❑ Other: Can be consistent with cost-of-service principles (1) and found to be in the public interest (1)	

Source: Author's construct. See Tables E3 and E4. Numbers in parentheses represent number of mentions (out of 21 applicable survey responses).

State Commission Policies

The public utility commissions have provide the central forum in which single-tariff pricing has been evaluated. Single-tariff pricing is a relevant regulatory policy issue only for the thirty (30) state public utility commissions with jurisdiction for multi-system utilities. Given this context, a clear majority of affected state commissions have allowed regulated water utilities to implement single-tariff pricing (22 state commissions).

Based on the commission survey and subsequent updates, single-tariff pricing is generally accepted in eight (8) states. A few states (such as Connecticut, Pennsylvania, and Texas) have recognized single-tariff pricing as a policy tool. Staff members at seventeen (17) commissions characterized the policies of their commissions as "case-by-case," indicating that the single-tariff pricing must be justified for every specific application (even when the policy is "generally accepted"). Numerous exemplary decisions can be cited.

Summary of State Public Utility Commission Policies on Single-Tariff Pricing for Water Utilities

Commission Policy	State Commissions	
Generally Accepted (8)	Connecticut	Pennsylvania
	Missouri	South Carolina
	North Carolina	Texas
	Oregon	Washington
Case-By-Case (17)	Single-Tariff Pricing Has Been Approved (14)	
	Arizona	New Hampshire (d) (f)
	Delaware (a)	New York
	Florida	New Jersey (e) (f)
	Idaho (not an issue)	Ohio
	Illinois	Vermont
	Indiana (b) (f)	Virginia
	Massachusetts (c) (f)	West Virginia
	Single-Tariff Pricing Has Not Been Approved (3)	
	California (g)	
	Maryland (not an issue)	
	Mississippi (not an issue)	
Never Considered (5)	Iowa	Maine
	Kentucky	Wisconsin
	Louisiana	
Not Applicable – No Multi-System Water Utilities (15)	Alabama	Nevada
	Alaska	New Mexico
	Arkansas	Oklahoma
	Colorado	Rhode Island
	Hawaii	Tennessee
	Kansas	Utah
	Montana	Wyoming
	Nebraska	
No Jurisdiction for Water Utilities (6)	Georgia	North Dakota
	Michigan	South Dakota
	Minnesota	Washington, D.C.

Source: Author's construct. See Table 12 for notes.

Guide for Readers

1. **Introduction.** The introductory section defines consolidated ratemaking, discusses general advantages and disadvantages of this approach, and provides the policy and regulatory context in which rate consolidation is considered.

2. **Background.** This section contemplates single-tariff pricing in light of an historical perspective and the prevailing economic regulatory literature. The concept of spatially differentiated pricing (or "zonal rates") also is considered.

3. **Spatial Pricing and Ratemaking Theory.** Principles of ratemaking and tradeoffs among efficiency, equity, and other policy goals, are considered. Goals unique to the water industry are identified. The section also contrasts pricing in theory with pricing in practice.

4. **Structural Issues in the Water Industry**. This section identifies ways in which pricing policies will shape the structural character of the water industry and the future of small water systems.

5. **Cost Profile of the Water Industry.** This section considers the cost profile of the water industry, including the relevance of economies of scale, the challenge of maintaining affordable water service for consumers, and the means to enhancing water system capacity.

6. **Examples of Single Tariff Pricing**. Numerical illustrations of rate consolidation are provided here, including examples from two recent cases in Indiana and New Hampshire.

7. **Public Utility Commission Role.** The role of the state public utility commissions is reviewed in this section, with an emphasis on how commission policies will affect the structure of the industry through consolidation.

8. **Commission Survey.** Results of a 1996 survey of commission staff members are presented. Based on a database derived from the survey, this section also identifies the characteristics of utilities that have implemented consolidated rates.

9. **Arguments in Favor and Against Rate Consolidation.** Commission staff views about the advantages and disadvantages of single-tariff pricing are presented.

10. **Commission Policies on Rate Consolidation**. This final section summarizes commission policies on rate consolidation and provides an overview of several key cases, including regulatory decisions from West Virginia, Pennsylvania, Massachusetts, Florida, Illinois, New Jersey, Missouri, Indiana, New York, and Connecticut. This section also considers legal challenges to the authority of regulators to approve consolidated rates.

1. Introduction

Definition

Consolidated rates or single-tariff pricing is the use of a unified rate structure for multiple water (or other) utility systems that are owned and operated by a single utility, but that may or may not be contiguous systems or physically interconnected. Under a system of single-tariff pricing, all customers of the utility pay the same rate for service, even though the individual systems providing service may vary in terms of the number of customers served, operating characteristics, and stand-alone costs. Single-tariff pricing essentially allows for allocating the average costs of combined systems in the course of ratemaking. In addition to the term "consolidated rates," the terms "single-rate structure," "uniform rates," "standard-tariff rates," "unified rates," and "rate equalization" sometimes are used in connection with the concept of single-tariff pricing.[1] For the purposes of this report, the terms consolidated rates and single-tariff pricing are used interchangeably.

Single-tariff pricing *de*-emphasizes spatial distinctions in costs. One of the best examples of a single tariff across an expansive and multicentric "service territory" is the single rate used in the United States for first-class postage. Indeed, consolidated rates sometimes are called "postage-stamp" rates. Conventional wisdom holds that uniform postal rates historically facilitated the extension of service to rural areas and that they continue to serve the national interest, provide equity and accessibility, and lower transaction costs.[2]

Examples of uniform pricing also can be found in the other public utility sectors. Long-distance, cellular-phone, and cable television services typically are priced according to the single-tariff concept (although the same terminology might not be used). Historically, at least, energy prices were established for a regional enfranchised service territory, regardless of the physical proximity of customers to specific utility facilities.[3] The other public utility sectors generally price across larger regional territories than water utilities, although facilities in the other sectors tend to be physically interconnected through transmission and distribution networks.

Use of single-tariff pricing by U.S. water utilities continues to be debated in regulatory policy circles, although many states have approved consolidated rates for one or more jurisdictional utilities and a few states have actively promoted the use of single-tariff pricing. A very prominent example of single-tariff pricing in the water sector comes from "across the pond." All of Great Britain's privatized regional water and wastewater utilities,

[1] The concept of uniformity is useful, but the term "uniform rates" probably should be reserved for rate structures that do not vary usage (or volumetric) charges by quantities (or blocks) of water usage.
[2] For a provocative discussion of both sides of the issue, see Ronald H. Coase, "The Economics of Uniform Pricing Systems," *Manchester School of Economics and Social Studies* Vol. 15 (May 1947): 139-56.
[3] In the context of restructuring and partial deregulation, methods for aggregating customers, allocating costs, and setting prices are changing dramatically. Spatial considerations might become less important in some instances, as in the purchase of electricity from a far-away generating facility. But market forces might also tend to group customers with similar cost profiles and undermine the goals of cost averaging.

and most of the smaller water companies, impose uniform rates for measured (metered) service, for both household and nonhousehold customers. A summary of recent British water tariffs is provided later in this report.

Single-tariff pricing can be absolute, applicable to all of the systems comprising the water utility. However, utilities also sometimes establish rates for regional zones consisting of subsets of water systems within the larger service territory. Rate consolidation sometimes is used for water systems that are contiguous but not interconnected, as well as noncontiguous noninterconnected systems, based on various criteria. Partial rate consolidation can be a compromise between individualized tariffs and complete single-tariff pricing, or part of a phase-in plan leading ultimately to a single tariff for the entire utility and all of its service territories. Figures 1 through 4 provide simple illustrations of the basic issues involved in rate consolidation for water utilities. A glossary of terms appears in Appendix A of this report.

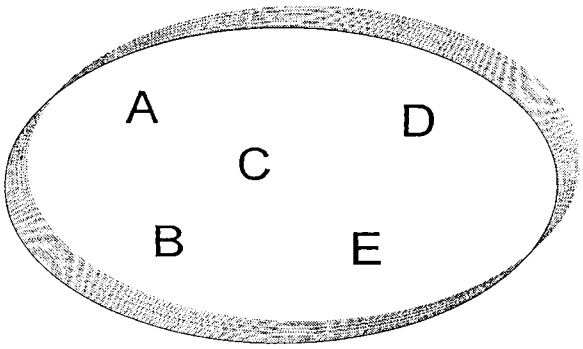

Figure 1. Water Systems without Physical Interconnection

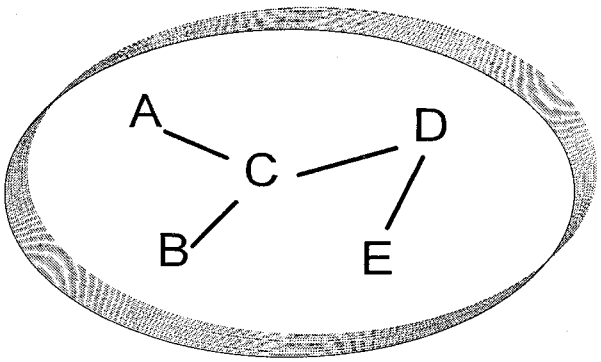

Figure 2. Water Systems with Physical Interconnection

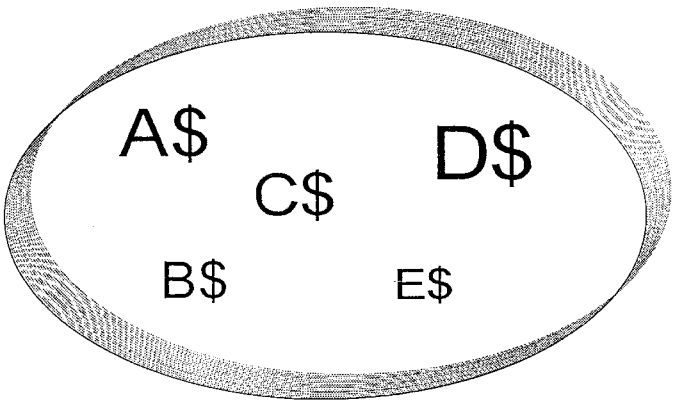

Figure 3. Water Systems with Stand-Alone Pricing

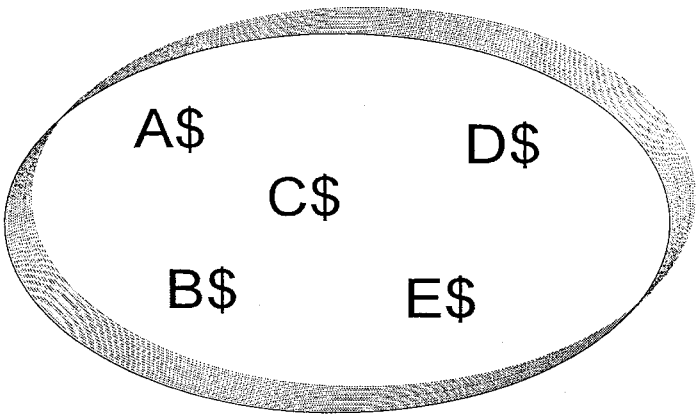

Figure 4. Water Systems with Consolidated Pricing

Key Advantages and Disadvantages

The primary advantages of single-tariff pricing are that it can lower administrative and regulatory costs, enhance financial capacity and capital deployment, achieve rate and revenue stability, and improve service affordability for customers of very small (or extremely small) water systems. The water industry's rising investment needs correlate with the interest in rate consolidation. A leading argument for single-tariff pricing made by multi-system water utilities is that each individual system eventually will require an infusion of capital for renovations and improvements; only the timing varies. Equalizing rates smoothes the effect of discrete cost spikes across systems and over time, much like insurance pooling. Single-tariff pricing also achieves equity to the extent that all customers of a given utility company pay the same price for comparable service.

Importantly, single-tariff pricing is a *pricing* strategy, not a *costing* strategy. Single-tariff pricing can appear to *lower* costs when in reality it simply *allocates* costs differently. In fact, one of the chief benefits of single-tariff pricing is that it greatly simplifies the allocation of common costs across separate facilities. Many water utilities believe that single-tariff pricing is more reflective of the consolidated cost of service. By itself, single-tariff pricing may not provide significant economies of scale because only the costs associated with the pricing process itself (including analytical, administrative, and regulatory costs) can be considered. Economies of scale in water production and management are achievable, irrespective of the rate structure implemented by the utility. Separating the cost side from the price side is crucial to understanding the true nature of the single-tariff pricing issue.

However, single-tariff pricing can lead to economies of scale in the water industry through secondary benefits. The secondary advantages are that single-tariff pricing can encourage industry consolidation, common management of smaller systems, and overall technical, financial, and managerial capacity. If regionalization *eventually* includes physical interconnection among some or all systems managed by a utility, more significant economies of scale can be realized. Larger utilities view consolidated rates as an incentive to engage in acquisitions because it can expedite the process and simplify ratemaking. The single-tariff price also can provide a powerful incentive for small communities as they contemplate selling their systems to larger utilities.

Other secondary advantages of consolidated rates include improved regulatory compliance by water utilities, the provision of universal service to customers who desire and need water service, and coordinated water resource protection, management, and planning. Even without physical interconnection, regional utilities can play a role in defining regional communities within which environmental services are provided. A consolidated rate for a larger community of customers will be more sustainable over time than stand-alone rates for smaller communities.

Consolidated rates also can improve the overall operational efficiency of a utility. Absent single-tariff pricing, the utility might be induced to invest in the system facing the highest

rates, even if this is a suboptimal choice from the standpoint of total system operations and economic value to the customer base as a whole. In other words, the utility might feel pressure to lower *prices* instead of lowering total system *costs*. With single-tariff pricing, utilities are induced to invest their available resources in the functional areas where the greatest improvement can be achieved at the lowest cost, to the benefit of all customers.

The primary disadvantages of single-tariff pricing are that it appears to undermine economic efficiency, distort price signals to customers, and manifest an inconsistency with traditional cost-of-service principles.[4] Although subsidies through some societal policy instruments (namely, taxes) are widely accepted, subsidies through utility rates generally are not.[5] Another potentially important equity concern is whether consolidated rates result in subsidies from the low-income customers in the low-cost area to higher-income customers in a high-cost area. This effect is mitigated to the extent that water use by low-income customers tends to be relatively low. Various aspects of the rate design also can lessen this type of subsidy.

Some communities and large-volume water users have opposed single-tariff pricing because they believe it is merely a means of subsidizing high-cost users at the expense of low-cost users. For this reason, single-tariff pricing also seems to be at odds with water conservation, in that it appears to weaken price signals and thus undermine efficient production and consumption. If rate consolidation involves a price decrease for some customers, one concern is that water consumption could increase.[6]

Secondary disadvantages are that—*absent other incentives or safeguards*—single-tariff pricing can provide some water utilities with incentives to overinvest in individual systems, disincentives for cost control, and a competitive advantage in the course of acquisitions. The latter concern applies only if one potential acquirer can offer consolidated rates and another cannot.[7]

These concerns are fundamental to utility economics, pricing, and regulation. However, any differences between single-tariff pricing and spatial pricing in terms of efficiency and other effects have not been well established from either a theoretical or empirical standpoint. Evaluating the *net* efficiency effects is especially difficult. Single-tariff pricing might lessen some kinds of efficiency (such as those related to spatial allocation of costs and price signals to customers), while improving other kinds of efficiency (such as those related to management and innovation). Of particular importance, but hardest to gauge, is whether single-tariff pricing and related restructuring can lead to long-run efficiency

[4] Steve H. Hanke, "On Water Tariff Equalization Policies," *Water Engineering and Management* 128 (August 1981): 33-34.

[5] The appropriateness of rate differentiation continues to be debated today in the context of both regulation and *de*regulation of public utility industries. The potential movement away from cost averaging for some services will affect customers, as well as the utilities that serve them.

[6] The price elasticity literature, however, is clearer about the usage effects of price increases than the usage effects of price decreases.

[7] In realty, competition for acquisitions is less a problem in the water industry than finding a single capable and willing buyer.

improvements in the water industry. Single-tariff pricing also has been underevaluated in terms of ratemaking criteria other than economic efficiency.

Single-Tariff Pricing as a Policy Issue

Single-tariff pricing is a public policy issue because it involves tradeoffs among competing policy objectives. Traditional cost-of-service principles and economic efficiency arguments, adhered to in the U.S. model of economic regulation as applied by the states to public utility monopolies, can lead to the conclusion that spatially-differentiated (or allocated) costs should be used as the basis for pricing utility services. Single-tariff pricing as a matter of public policy in this context requires an explicit recognition of the tradeoffs involved.

Specifically, single-tariff pricing involves a tradeoff between conventional ideas about cost-based rates, economic efficiency, and other legitimate ratemaking goals. These other goals include, for example, small-system capacity, rate and revenue stability, universal service, and compliance with environmental standards. A fine-tuned price signal that appears to be economically efficient, for example, can result in considerably less rate and revenue stability. Likewise, a conservation-oriented rate may not be affordable to customers. Evaluating ratemaking trade-offs can be complex. The decisionmaking process can be greatly enhanced by information and analysis, and decisions can be made more rational, but a certain degree of judgment ultimately is required in determining whether a particular option is in the public interest.

The short-term goals of single-tariff pricing tend to focus on enhancing the financial capacity of water systems and making rates more affordable for water customers. The long-term goals, however, are related to structural change in the water industry. Specifically, single-tariff pricing is regarded as a means to consolidating the management and operation of water systems, or "regionalization," to achieve multiple policy goals.

The Regulatory Context

Single-tariff pricing has received more attention in the context of economic regulation by the state public utility commissions than in context of public ownership (where regulation is limited or nonexistent). A compilation of citations to selected commission orders on the issue can be found in Appendix B of this report. As discussed later in this report, the issue is not equally relevant in every jurisdiction. Not all states regulate water utilities, and for those that have jurisdiction, multi-system water utilities may not be present. Single-tariff pricing also has not been raised as an issue for every multi-system water utility

Single-tariff pricing was placed on the regulatory policy agenda by the investor-owned water industry. Some water industry officials have made a strong case for single-tariff pricing before regulators. Several of the regional affiliates of the American Water Works

Company have taken the lead in advocating this method of pricing before the state public utility commissions, including the commissions in Illinois, Indiana, New Jersey, and Pennsylvania. However, other multi-system utilities (not affiliated with American Water Works), commission staff members, and other stakeholders also have raised the potential use of single-tariff pricing.

The many proceedings (and sequences of proceedings within certain jurisdictions) in which the issue of single-tariff pricing has been raised is suggestive of the *case-by-case* manner by which single-tariff pricing policy has largely developed. This is due in part to the nature of commission decisionmaking: regulators must rule on the record of evidence put before them in a given proceeding and each individual utility generally must make its own case for implementation. However, some commissions have explicitly encouraged the movement toward single-tariff pricing and a few have incorporated this approach into general policies and specific policies dealing with acquisitions of smaller systems.

Opponents have argued forcefully before the commissions that single-tariff pricing contradicts fundamental regulatory principles and conventions, as well as undermines the commission oversight responsibility:

> Tariff consolidation, sometimes called Single Tariff Pricing (STP), breaks the connection between costs and rates. It is a fundamental tenet of utility ratemaking policy that the cost causer should also be the cost payer. STP runs counter to this principle. Under and STP scheme, customers who receive no service from the core system would receive a considerable subsidy. Likewise, customers who do not impose a load on the [noncore systems] would be forced to pay a portion of the cost of providing that service indefinitely. A customer located in the core system would be encouraged to conserve water to an excessive degree. Conversely, a [noncore customer] would bear a smaller economic penalty for using more water than necessary.
>
> It is also important to note that once a regime of subsidies has been initiated, it is very difficult to discontinue this practice due to customer impact considerations, even if it has been found to create undesirable consequences. Subsidies are understandably popular among those who receive them, and it is equally understandable that they will resist their being terminated. Conversely, subsidies are understandably unpopular among those who pay them....
>
> If rates were to be consolidated, there would be no reason to maintain separate books and records for each of the [systems]...[8] However, this loss of operating and financial data would destroy the ability to evaluate the effectiveness and efficiency of the Company's operation of the [systems]. As a result, the [public utility

[8] This point seems somewhat overstated. Most consolidated utilities maintain detailed cost and other data on their operating units for planning and management purposes. Under single-tariff pricing, the need for an acceptable method to allocate *common* costs across distinct systems for ratemaking purposes is lessened or eliminated.

> commission] would lose its ability to exercise regulatory oversight and control as it pertains to these systems.[9]

Most of the commissions historically shared this predilection for "cost-based" rates. In numerous recent decisions involving a variety of utilities and issues, however, many of the state public utility commissions have found that single-tariff pricing is *in the public interest* and that it comports with prevailing standards concerning just, reasonable, and nondiscriminatory rates. Some commissions have found that single-tariff pricing is not inconsistent with cost-of-service principles or with commission ratemaking authority.

A variety of specific rationales (or combinations thereof) have been put forth by some of the commissions to justify approval of single-tariff pricing: it addresses pragmatic concerns affecting utilities and customers (namely, revenue stability and mitigation of rate shock); it is consistent with consolidated management, operations, financing, and corporate structures; it reduces regulatory caseload and costs; and it results in comparable prices for comparable services produced from comparable facilities. Many investor-owned utilities have strongly urged regulators to recognize that these companies provide all of their customers the same brand-name product (a safe and reliable supply of potable water) and that single-tariff pricing will also make the product more affordable. Essentially, single-tariff pricing makes it possible for all customers to share in the total economies of scale and scope achieved by the utility corporation.

Asserting regulatory authority to approve single-tariff pricing in some jurisdictions has not been an easy task. The issue often arises in the context of other complex regulatory issues related to water utility rates, management, operations, and acquisition practices. Regulatory rulings must be within the scope of commission authority and the boundaries set by state legislatures and the courts; if not, commission decisions can be legally challenged. Nevertheless, as explored later in this report, the state public utility commissions have approved the use of single-tariff pricing for many multi-system water utilities. Several specific regulatory determinations involving single-tariff pricing are reviewed later in this report.

[9] Ernest Harwig, Direct Testimony before the New Hampshire Public Utilities Commission in DR 97-058, Pennichuck Water Works, Inc. (1997).

2. Background

With few exceptions, the literature on public utility economics and ratemaking–including ratemaking for the water industry–sheds little direct light on the issue of single-tariff pricing. The leading scholarly work on utility economics mainly considers the economic characteristics of telecommunications and energy industries, where private ownership prevails, regionalization is pervasive, physical interconnection is the norm, and costs of transmission are low.[10] The leading manuals on water utility ratemaking published by the American Water Works Association convey little (if any) information about the single-tariff pricing method, a fact that probably undermines the method's institutional acceptance.[11] A cursory review of other promising bodies of literature, such as economic geography, does not readily yield information on this apparently understudied issue.

The limited discussion of the spatial dimension of utility ratemaking appears mainly within the literature on legal doctrine and in the consideration of zonal pricing.

The Municipal-Unit Doctrine

In the adolescent years of the public utility industries, legal scholars debated whether costs of providing service should be allocated spatially. Specifically, the debate centered on the cost differences associated with providing service to urban and rural areas, the latter of which can be more expensive to serve because of the cost of service-line extensions and lack of economies of scale (for example, numerous users at the end of the line). The known result of strictly cost-based pricing would have been to discourage the extension of "modern" services to rural areas. Based on the essential nature of utility services, the consequence would have been marked differences in the quality of life between urban and rural dwellers, as well as underdevelopment of rural communities.

A series of legal precedents seemed to establish municipalities as ratemaking units for utilities serving multiple cities. The "municipal-unit doctrine" refers to the treatment of a municipality as a distinct service territory and unit for cost allocation and ratemaking purposes (that is, "city-based" rates). In a 1934 review, however, Robert D. Armstrong passionately rejected the "municipal-unit doctrine," primarily on economic-development grounds:

> System utilities have made service available to the entire public, both urban and rural, within large areas. This development serves a sound social policy. Any regulatory policy or rule of law which would curtail it or rob it of its just reward would be unfortunate and unwise. If each locality were required to stand upon

[10] See Charles F. Phillips, Jr., *The Regulation of Public Utilities* (Arlington, VA: Public Utilities Reports, Inc., 1993).

[11] American Water Works Association, *Water Rates (M1), Water Rates and Related Charges (M26),* and *Alternative Rates (M34)* (Denver, CO: American Water Works Association, 1983, 1983, and 1992, respectively).

> its own bottom, so to speak, rural and village extension and development would be discouraged, and in many cases existing service abandoned.
>
> This would hurt the larger communities as well as the rural localities. It would tend to eliminate the rural and village patrons, who now contribute something to system overhead and return, and thus lessen its burden upon city and town patrons. It would reverse the process by which large scale production and distribution have been made possible, with more dependable service and lower rates for all. It might ultimately require higher rates within the larger municipalities in order to produce a reasonable unit return.
>
> Moreover, anything that would discourage the development and prosperity of the tributary rural and village territory would react unfavorably on its economic center and business capital.[12]

Armstrong also cites addresses by Governor (and President-to-be) Franklin D. Roosevelt in 1929 and Harvard Professor Philip Cabot in 1932, both of whom advocated "greater uniformity in public utility rates despite differences in cost on broad grounds of public policy."[13] At the 1929 State Fair, Roosevelt "attacked the inequality and lack of standardization" of utility rates and declared the situation "manifestly unfair":

> Now, I am sorry to say that the principle of reasonably equal service at reasonably equal cost to all the people of the State has not been carried out with regard to the two latest forms of public service—the telephone and electricity. For some reason (the history of which it is unnecessary to go into) the original telephone companies were allowed to charge different kinds of rates, and now, when practically all telephones are controlled by the greatest of all American mergers, we do not insist on either uniform service or uniform rate. . .
>
> The other example, and one which is even more glaring in its unfairness, is that of the use of electricity in the homes. The railroad principle of fairly uniform rates has been thrown to the winds even by the public regulating body known as the Public Service Commission. Is it [now] time to stop and ask the question: "Why does electricity in the home, the electric lights, electric refrigerator, electric sewing machine, the home machinery, cost as high as from 15 to 20 cents per kilowatt hour in some localities and as low as from 4 to 6 cents per kilowatt hour in other localities." Why should families in one section be so grossly penalized over families in another section?

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[12] Robert D. Armstrong, "The Municipality as a Unit in Ratemaking and Confiscation Cases, *Michigan Law Review* 32 No. 3 (January 1934), footnotes omitted. Armstrong served as a hearing examiner with the Indiana Commission and thereafter with the Interstate Commerce Commission.

[13] Armstrong (1934), 292n.

> This difference in charges is true not merely in its application to regions as large as counties, but is true in respect to towns adjoining each other and houses separated only by a mile or two. This is perhaps one reason why even today nearly two-thirds of all the farm houses in the State of New York have no electricity. I am wondering whether it is not time for the people of this State to ask for the application of a more uniform rate and a more uniform system of charging for installation.[14]

Utility regulators have a considerable degree of discretion in ratemaking, but their authority is derived from state legislatures and checked routinely by the courts. In 1933, for example, the Supreme Court upheld a decision by the Indiana commission to treat municipalities as separate ratemaking units pursuant to state law. In response, however, the legislature expressly authorized the commission to prescribe uniform rates on a regional basis. This section continues to hold a place in the Indiana Code:

> Every public utility is required to furnish reasonably adequate service and facilities. The charge made by any public utility for any service rendered or to be rendered either directly or in connection therewith shall be reasonable and just, and every unjust or unreasonable charge for such service is prohibited and declared unlawful. The commission, in order to expedite the determination of rate questions, or to avoid unnecessary and unreasonable expense, or to avoid discrimination in rates between classes of customers, or, whenever in the judgment of the commission public interest so requires, may, for ratemaking and accounting purposes, or either of them, consider a single municipality and/or two (2) or more municipalities and/or the adjacent and/or intervening rural territory as a regional unit where the same utility serves such region, and may within such region prescribe uniform rates for consumers or patrons of the same class. . .[15]

The policy theory deployed to reject the municipal-unit doctrine accepts a fairly sizable subsidy of rural services in the interest of achieving societal policy goals. Historically, and for public policy reasons, rural utility services also were subsidized through governmental grant and loan programs. In the public sector, local governmental subsidies related to water and wastewater services are relatively common.[16]

Following the apparent demise of the municipal-unit doctrine, most investor-owned telecommunications and energy services seemed to price their products on a service-territory basis. Today, this issue has been eclipsed by the trend toward competitive pricing. Price theory suggests that competitive firms will offer the same price, based on marginal cost, at all locations. Unregulated monopolists will maximize profits by engaging in price discrimination among markets. According to B. Peter Pashigian, the net

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[14] Ibid.

[15] Indiana Code §8-1-2-4 Sec. 4.

[16] Another violation of efficiency occurs when subsidies flow *from* the water system to the municipal budget.

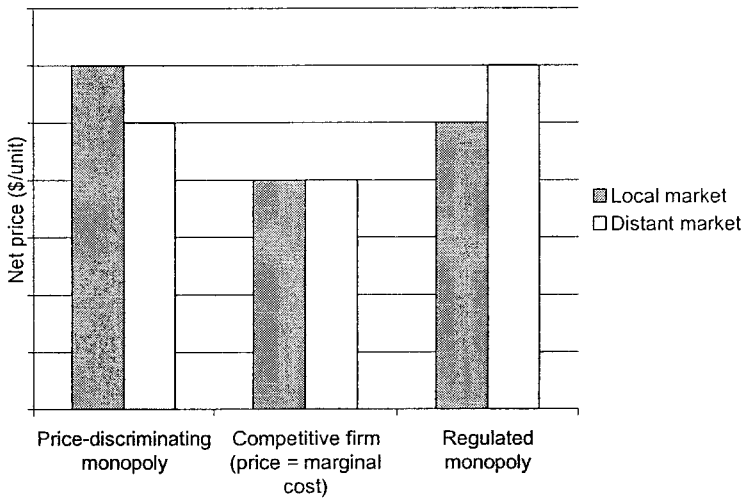

Figure 5. Illustration of Pricing Practices by Firms

Source: Adapted from B. Peter Pashigian, *Price Theory and Applications* (New York: McGraw Hill, 1994), 467.

price will be *lower* in the distant market under geographic price discrimination because the price-discriminating monopolist absorbs the freight costs associated with distant sales.[17]

Of course, economic regulation tends to reverse this finding, resulting in higher prices to higher cost areas (namely, distant or rural markets). Pricing theory suggests, however, that consolidated rates may be consistent with the behavior of competitive firms. The generalized disparity in pricing among different types of firms is illustrated in Figure 5.

Competition places a greater emphasis on overall efficiency as a determinant of price levels, rather than on allocating costs according to space or other criteria used in monopoly ratemaking. Competitive pricing also shifts some attention away from the cost of service toward the value of service. Pricing flexibility can help firms respond to competitive forces, focus on service, and improve overall efficiency. When left to their discretion, many multisystem utilities will opt for the competitive advantage of a consolidated rate. Absent competition, however, the rate will not achieve efficiency.

[17] B. Peter Pashigian, *Price Theory and Applications* (New York: McGraw Hill, 1994), 467.

Spatial Pricing

Analysts seem to agree that utility costs vary *spatially;* that is, the cost of serving one area generally is not matched by the cost of serving another area. For water utilities, differences in elevation, climate, physical terrain, the age of the infrastructure, the density of the service population, and a host of other factors will tend to affect costs even for service territories that otherwise appear similar. Differences in the proximity to water sources, the type of source (surface water versus groundwater), the quality of source water, and implemented treatment methods will tend to produce substantial cost differences.

Assumptions about efficiency and concerns about equity in cost allocation also can lead to zonal pricing, by which utilities vary prices according to spatial variations in costs among customer groups that are grouped into zones, districts, or service areas. Zonal pricing recognizes that the location of consumers within a larger service area can affect the cost of providing service.[18]

With zonal pricing, rates are differentiated according to substantial differences in the cost of serving different areas. Zones generally are defined in spatial terms and represent geographic clusters of customers with similar cost characteristics. Differences in costs among zones may be attributed to differences in distribution system costs, which may be due to differences in the physical plant serving the zones (including age). A more frequently cited reason for spatially differentiated pricing, however, is the variation in pumping costs caused by differences in the proximity to facilities, density of the service population, and particularly elevation. For practical purposes, and as used in this report, zonal pricing is essentially the same as spatially differentiated pricing.

The zonal price can reflect not only the proximity of groups to source and treatment facilities, and differences in terrain, but also the different peaking characteristics that service areas might present. Economist Robert Greene describes a situation in which three zones present alternative distance and peaking characteristics that can be used to guide the efficient allocation of capacity costs for each zone.[19] In this case, customers assume a greater cost burden when they are further from the treatment plant and when they contribute to the peak period of water usage. Greene's example of the cost allocation based on zonal differences appears in Table 1. The cost allocation reflects the fact that users impose different capacity costs on water systems based on their location, well as their contribution to the system's peak loads.

According to Greene:

[18] Janice A. Beecher, Patrick C. Mann, and John D. Stanford, *Meeting Water Utility Revenue Requirements: Financing and Ratemaking Alternatives* (Columbus, OH: The National Regulatory Research Institute, 1993).

[19] Robert Lee Greene, *Welfare Economics and Peak Load Pricing* (Gainesville, FL: University of Florida Press, 1970).

Table 1
Cost Allocation Under Zonal Pricing

Zone	Distance from the Treatment Plant	Peak Period of Usage	Efficient Allocation of the Zone's Capacity Costs
Zone A	1 mile	Period I	All users in Zones A, B, and C
Zone B	1-2 miles	Period II	All Period II users in Zones B and C
Zone C	2-3 miles	Period I	Period I users in Zone C

Source: Adapted from Robert Lee Greene, *Welfare Economics and Peak Load Pricing* (Gainesville, FL: University of Florida Press, 1970), 60.

> The importance of zone pricing rests not only in the proper allocation of resources in water use. There is considerable significance with respect to land use and other objectives. In a discussion of improper pricing policies tied to marginal rents and the constraints imposed by these rents. . . A zone pricing solution can be used for rate differentials in both seasonal and daily peak load problems. . . Zone pricing can also be used to adjust rates in accordance with cost differentials arising from such factors as geographical characteristics and population density. . .[20]

The key issue in implementing zonal rates is one of cost justification. If substantial cost differences exist within a service area, then zonal rates may be an appropriate form of rate unbundling that ostensibly attains more efficient water rates.

The efficiency gain assumes that the zonal rate is cost-based and that the transaction costs associated with unbundling are justified by the efficiency gains. Zonal rates that are arbitrary (for example, rates that bear no relationship to cost variations or rates that are based solely on geopolitical boundaries) will introduce inefficiencies. The expense of developing zonal cost data probably has limited the application of zonal pricing. A prerequisite to efficient zonal pricing is the capability to accurately calculate the cost differences associated with providing service to different zones within a utility's service territory.

Economic and engineering arguments against zonal pricing can be made.[21] Capital-intensive utility systems should be designed for optimal performance of all utility functions (supply, treatment, distribution, and so on) within a service territory. Spatial differentiation within the service territory might subvert this general optimum. In other words, the utility

[20] Ibid., 61-62.
[21] Beecher, et al. (1993).

does not deploy resources in the most economically beneficial manner. Another potential disadvantage of zonal pricing is that it can accentuate the problem of localized cost and rate shock associated with infrastructure replacements. By broadening the customer base, a uniform or average rate will cushion the shock and temper its adverse effects (such as revenue instability).

Zonal rates also raise concerns about equity and perceptions of equity. Obviously, zonal rates usually will be met with considerable resistance from the groups of consumers asked to pay higher water rates. In some contexts, zonal pricing might constitute an undesirable form of price discrimination.

Zonal pricing is used by the water industry to some degree, although not necessarily by that name. Wholesale water rates might qualify as an example because they typically reflect spatial differences in costs. Utilities that set different retail prices for districts served include the California-American Water Company and the Los Angeles Suburban Water Company.[22] A more common form of zonal pricing used by publicly owned utilities is the rate differentiation for service inside and outside municipal boundaries. Fairfield, California provides an example of spatially differentiated pricing, both within the city and between residents and nonresidents (see Table 2). As a generalization, municipal utilities are more likely to use inside-city/outside-city pricing and investor-owned utilities are more likely to seek approval for rate uniformity across service territories.

Table 2
Example of Municipal Zonal Rates for Residential Water Customers

Residential Water Charges	Rate
Service charge	$0.50 per day
Water-use charge	$1.35 per 100 cubic feet
Zone 3 (200 feet and over)	$1.67 per 100 cubic feet
Zone 5 (400 feet and over)	$2.00 per 100 cubic feet
Pneumatic Pump Zones	
Zones 1 and 2	$1.57 per 100 cubic feet
Zones 3 and 4	$1.89 per 100 cubic feet
Zone 5	$2.22 per 100 cubic feet
Outside City Charge	
Service charge	$0.75 per day
Water-use charge	$2.02 per 100 cubic feet

Source: City of Fairfield California Utility Rates, as of January 1, 1999. 100 cubic feet = 748 gallons. (http://www-e-v.com/fairfield/government/public_works/rates.htm).

[22] Raftelis Environmental Consulting Group, *1996 Water and Wastewater Rate Survey* (Charlotte, NC: Raftelis Environmental Consulting Group, 1996).

For a variety of reasons, zonal pricing does not appear to be the prevailing model for retail water pricing. Importantly, costs can vary *within* physically interconnected service territories by magnitudes as great as they might vary between noninterconnected systems. By and large, many cost differentials associated with spatial considerations are essentially disregarded in the ratemaking process for public utility systems.

Spatial Pricing and the Telephone Industry

The rejection of zonal pricing in the debate over statewide telephone rates seems to come closest to providing a rationale for single-tariff pricing by multi-system water utilities. According to Charles Phillips:

> While each exchange is a distinct unit for rate-quoting purposes, the former Bell System companies have generally established rates on a statewide basis. Essentially, the statewide basis provides that the total costs of furnishing telephone service and the resulting revenue requirements are considered for the state as a unit. This practice recognizes that telephone service, both exchange and intrastate toll, furnished by a given company through a state, is, in reality, an integrated whole, all portions of which are interdependent. The objective is to apply throughout the state a well-balanced and coordinated pattern of rate treatment, providing rates that are uniform under substantially like conditions and producing, in the aggregate, reasonable earnings on the company's total telephone operations within the state.
>
> The statewide basis has five important advantages over consideration of individual exchanges. First, the statewide basis permits more people to have better service at a reasonable price. Some small areas, if forced to pay their own way, might have no service at all. Needed plant replacements or additions might be postponed if local customers had to cover their full costs, resulting in deterioration of local service within the exchange and of toll service to and from it. Second, on the statewide basis, customers pay like charges for like amounts of service. If each exchange had to stand on its own feet, customers' charges would vary with physical characteristics of the exchange areas, age of plant, type of equipment and other factors affecting costs, but not necessarily affecting the service rendered. The statewide basis averages out such factors.
>
> Third, customers seem better satisfied with statewide rates, since the application of uniform schedules avoids any questions of discrimination or unfair advantage to pressure groups in individual exchanges. Fourth, the statewide basis tends to stabilize rate levels by providing a broad rate basis. Risks are shared so that a community suffering from flood, storm or other natural disaster or from some local economic difficulty (e.g., the removal of a major industry) need not pay higher telephone rates such as would be required if telephone operations in that exchange had to meet these conditions single-handedly. Finally, the statewide basis is more workable and makes the regulatory process less cumbersome and expensive to both

> the public and the company involved. It avoids multiplicity of rate cases for each individual exchange. It simplifies handling of questions and complaints by the regulatory commissions and administration by the companies.
>
> At the same time, it should be pointed out that the statewide basis results in some subscribers subsidizing other subscribers. Because exchange telephone service is more valuable to customers in the larger service areas, they are willing to pay more for their service. Since their average cash incomes are greater, they are able to pay more. Lower rates in the small towns and rural areas, where average money incomes are relatively low, encourage telephone use and development in these places. Once again, this is an example of how rate discrimination has been used to achieve a socially desirable objective, in this case the widespread development of telephone usage through the country.[23]

Phillips also discusses how "nationwide averaging has been used in establishing interstate toll rates, under which toll rates are the same for equal distances throughout the continental United States, despite differences in the costs involved"[24] A nationwide rate, he acknowledges, has "all of the advantages of statewide rates, but it results in internal subsidization" and raises a variety of competitive issues as well.

Counterpoint

In a direct and provocative treatment of the "uniform pricing" issue, economist Ronald Coase acknowledged that the key arguments favoring uniformity are founded on the view that certain services (namely, utility services) are considered essential and that the undertaking as a whole can be "self-supporting."[25] However, Coase notes the intellectual disagreement among early postmasters (also economists) over whether postage stamp rates actually served the interests of rural communities.

Absent a governmental subsidy, according to Coase, a uniform price actually might cause a provider to avoid or delay extending service to high-cost areas, *even if the customers in high-cost areas are willing to cover the additional costs through rates (or surcharges).* Adding high-cost customers to the mix increases the average cost of production and decreases the economic well-being of the utility. The magnitude of this effect depends on the relative mix of high-cost and low-cost service. Coase makes, and then relaxes, a number of assumptions that may or may not be valid but he does not consider the role of economic regulation. In practice, a forward-looking ratesetting process that accounts for the total cost of service throughout the consolidated service territory neutralizes the disincentive Coase identifies. Indeed, the primary and practical purpose of rate consolidation had been to extend service *while* maintaining the utility's financial health.

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[23] Phillips (1993), 517-518.
[24] Phillips (1993), 522.
[25] Coase, "The Economics of Uniform Pricing Systems."

3. Spatial Pricing and Ratemaking Theory

Theoretical Issues

The defining engineering, economic, structural, and institutional characteristics of the water industry generally are not contemplated in the literature establishing the basic principles of utility ratemaking. The central issue of whether physical interconnection should be required for single-tariff pricing by multi-system water utilities is not well addressed. Because other utility infrastructures—electricity, electricity, natural gas, telecommunications—have a high degree of interconnection through transmission grids, the acceptability of cost averaging for non-interconnected systems is a theoretical problem unique to the water and wastewater industries. Although energy and telecommunications providers experience spatial differences in cost, these differences are generally not reflected in prices.

In the prevailing theories used in ratemaking and regulation, the concepts of "due" (or just and reasonable) and "undue" (or unjust and unreasonable) price discrimination are contemplated with regard to customers classes but not with regard to spatially defined systems. Separate prices for separate systems owned by a common entity reflect assumptions about the implications of the cost allocation for efficiency. It can be argued that water costs are allocated (and prices are charged) on a spatial basis primarily because they *can be,* rather than that they *should be* for unequivocal theoretical or empirical reasons. In other words, the costs of providing utility service can be approximated for individual operations (with corporate common costs allocated among them), but the benefits and desirability of doing so are contingent on other considerations.

A logical (if not well documented) argument can be made that spatial pricing comports with cost-of-service principles and enhances allocative efficiency: customers of systems with higher costs pay higher rates and customers of systems with lower costs pay lower rates. The degree of subsidy or inefficiency introduced with single-tariff pricing, and whether or not it is acceptable, depends in part on the differential in costs among systems. A small differential with a minimal rate impact will be less controversial than a large differential with a substantial rate impact. Little guidance is available on to what extent of cost averaging through single-tariff pricing would constitute an inappropriate level of subsidy, undue price discrimination, or more generally an abuse of monopoly power.

However, with or without single-tariff pricing, utility rates can be more or less efficient depending on other features of the rate (such as the mix of fixed and variable charges, the number of rate blocks, rate-block differentials, and seasonal differentials). These features can promote efficient water use and can do so when used in conjunction with single-tariff pricing. Moreover, and perhaps more importantly, the cost of service is not the only guiding principle and efficiency is not the only goal of public utility ratemaking and policymaking, as discussed later in this report.

In reality, virtually all methods of utility rate design require a considerable degree of cost averaging. The obvious example is in the establishment of rates by customer classes (for example, residential, commercial, industrial, and wholesale). But many utility costs are associated with common operational and management functions. Common costs are allocated to customer groups according to one of several available methodologies. For multi-system utilities that do not use single-tariff pricing, common costs must be allocated spatially as well. Allocating common costs requires the analyst to make assumptions about underlying cost drivers and establish yet another layer of averaging. The entire process of cost allocation and rate design is as much art as it is science, and has at least as much to do with equity as it does efficiency.

In many jurisdictions, the *status quo* presents a challenge for utilities. Based on the prevailing theoretical assumptions, the burden of proof has rested on water utilities to justify the use of single-tariff pricing. In other words, the prevailing assumption is that deviations from spatial allocation of costs (such as the movement toward consolidated rates) must be justified. An alternative approach would be to begin with a single tariff and specify the circumstances under which spatial allocation of costs is justified because of concerns about efficiency, equity, subsidies, undue discrimination, or other ratemaking or policy concerns. This might shift attention to the use of extra-tariff instruments, such as surcharges, to make price adjustments needed to encourage efficiency and accomplish other purposes.

Evaluation Issues

The appropriateness of reflecting spatial differences in cost in prices can be evaluated according to traditional and modern ratemaking criteria. The general criteria for many public policies, and for utility ratemaking, often emphasize competing goals. Although it always seems desirable to achieve public policy goals efficiently, efficiency itself is not the only goal of policymaking:

> Of course, efficiency is not the only societal value. Human dignity, economic opportunity, and political participation are values that deserve consideration along with efficiency. On occasion, public decision makers or ourselves, as members of society, may wish to give up some economic efficiency to protect human life, make the final distribution of goods more equitable, or promote fairness in the distribution process. As analysts we have a responsibility to confront these multiple values and the potential conflicts among them.[26]

The emphasis on, concept of, and assumptions about efficiency shape views about what is just, fair, or equitable. Political philosophers offer alternative perspectives. The Rawlsian theory of justice, which holds that public policies should be used to

[26] David L Weimer and Aidan R. Vining, *Policy Analysis: Concepts and Practice* (Englewood Cliffs, NJ: Prentice-Hall, 1989), 31.

provide the greatest benefit to society's least advantaged, is perhaps the best example of a countervailing philosophy.[27]

Ratemaking Criteria

Ratemaking and rate design are guided by certain fundamental principles that are well established and well accepted in the regulatory community. These principles provide guidance, but are not decisive because each involves a degree of subjectivity and some principle might directly clash with others.

Most ratemaking analysts rely substantially on James Bonbright's eight criteria for a sound or desirable rate structure:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
✓3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
✓6. Fairness of the specific rates in the appointment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
✓8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company;
   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.[28]

As indicated by check mark (✓), Bonbright considered three criteria—revenue sufficiency, fairness, and efficiency—to be especially important.[29] Despite the passage of time, Bonbright's criteria remain quintessential. Table 3 presents a qualitative analysis of the consistency of single-tariff pricing with Bonbright's traditional criteria (items 1 though 8). Five additional policy criteria that are especially relevant to modern water pricing also are presented (items a through e).

Consolidated rates generally seem to meet the test of Bonbright's first five criteria. If practicality depends in part on customer acceptance, then acceptance becomes a

[27] John Rawls, *A Theory of Justice* (Cambridge, MA: Belknap Press of Harvard University Press, 1971).
[28] Phillips (1993), 434-435. Based on James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961).
[29] Phillips (1993), 434-435.

determinant. Other aspects of practicality, namely simplicity, understandability, and feasibility of application (or implementation) seem very compatible with single-tariff pricing. The last three criteria are labeled as indeterminate because their compatibility with rate consolidation depends on other policies or practices, or on the subjective judgment of the evaluator. While single-tariff pricing is not necessarily consistent with these criteria, neither is it clearly inconsistent. On the issue of fairness, single-tariff pricing might be considered unfair on the basis of subsidization, but fair on the basis of sharing burdens at a reasonable cost. On the issue of efficiency, other features of a tariff also affect the accuracy of price signals.

The five additional criteria included represent a select group of other potentially relevant policy goals in relation to single-tariff pricing for the water industry. Resource planning is considered indeterminate because planning incentives and outcomes probably are more heavily influenced by the structural character of the water industry than by rate design. However, single-tariff pricing seems rather consistent with four other criteria—standards compliance, customer affordability, industry restructuring, and institutional legitimacy. The last criterion, institutional legitimacy, is somewhat of a composite indicator. The assertion of consistency reflects the generally positive support for single-tariff pricing by the state public utility commissions and the courts.

Table 3
Consistency of Single-Tariff Pricing With Ratemaking Criteria

Criterion	Consistency of Single-Tariff Pricing with Criterion
Bonbright Criteria	
1. Practicality	Generally consistent (if accepted)
2. Interpretability	Generally consistent
3. Revenue recovery	Generally consistent
4. Revenue stability	Generally consistent
5. Rate stability	Generally consistent
6. Fair cost allocation/equity	Indeterminate
7. Discrimination avoidance	Indeterminate
8. Efficient resource use	Indeterminate
Additional Criteria	
a. Resource planning	Indeterminate
b. Standards compliance	Generally consistent
c. Customer affordability	Generally consistent
d. Industry restructuring	Generally consistent
e. Institutional legitimacy	Generally consistent

Source: Author's construct. Criteria 1 through 8 are from James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961).

Directly or indirectly, these criteria figure prominently in the consideration of rate consolidation. Other analysts surely could raise other relevant considerations. No attempt is made here to weight the criteria according to perceived importance; this is a task left to policymakers. In reality, the efficiency criterion is assigned considerable weight in ratemaking, as well as in policymaking in general. In other words, divergence from efficient solutions (or solutions that are perceived to be efficient) must be well justified.

The Efficiency Criterion

Economic theory argues for utility pricing that promotes overall *efficiency* for society. An efficient price signal leads consumers to consume, and producers to produce, an appropriate amount of a good or service. Prices that are too low can lead to overconsumption (and underproduction); prices that are too high can lead to underconsumption (and overproduction). The mismatch of supply and demand, and the "welfare loss" associated with it, has rippling effects throughout the economy because in using excessive resources to produce a good, or spending too much for that good, society foregoes opportunities to use those resources or make those expenditures elsewhere.

Economic theory also argues for utility pricing that is *equitable* in terms of allocating costs to those responsible for those costs.[30] In this conception, equity essentially serves efficiency goals. Three kinds of equity can be considered. Horizontal equity suggests that those who impose similar costs should pay the same rate. A related ratemaking principle is that rates should be "nondiscriminatory." Vertical equity suggests that those who impose different costs should pay different rates that reflect those cost differences. Ratemaking allows for "due discrimination" when costs among customer groups vary substantially. Finally, intergenerational equity considers equity along a temporal dimension, suggesting that one generation of customers should not be forced to cover costs imposed by another generation of customers.

Economists long have argued for prices that reflect costs and against subsidies that distort price signals. Modern pricing theory more specifically calls for pricing based on marginal costs; that is, prices should reflect the incremental cost of producing an additional increment of a good. Prices based on long-term marginal costs will help achieve long-term efficiency in deploying resources. Efficiency is a fundamental goal but it is not the only goal of utility pricing. Pricing also must help achieve a delicate balance between the interests of the utility and the interests of ratepayers, and in doing so satisfy the public interest standard.

[30] Of course, other theoretical perspectives will argue for different kinds of equity, such as social and political equity.

Other Criteria

Another vitally important ratemaking principle centers on the avoidance of "undue" price discrimination. An important issue for regulators is whether the level of price discrimination under either single-tariff pricing or stand-alone pricing is "due or undue," that is, whether or not it is justified. According to Charles Phillips:

> Price discrimination occurs when a seller establishes for the same product or service different rates that are not justified entirely by differences in cost, or the same rate where differences in cost would justify differences in price. . . [I]t would be theoretically possible for a firm to charge each customer a different rate. . .[31]

The often-cited legal standard of "undue discrimination" does not point regulators or the courts to particular solutions, as articulated by Richard J. Pierce:

> Most regulatory statutes forbid "undue discrimination" in the relationship among the rates charged different customers or classes of customers. This statutory standard is almost completely devoid of meaning, however. By using the adjective "undue," the standard obviously authorizes some forms of price discrimination, but it says nothing that would help an agency or a court distinguish between permissible and impermissible rate differentials.
>
> Much of the case law purporting to distinguish between due and undue discrimination is affirmatively misleading. . .
>
> [The Supreme] Court's holding in *Hope* applies with equal force to rate design decisions. An agency's decision has a "presumption of validity," and anyone seeking to overturn it has "the heavy burden of showing that it is invalid." The agency is "not bound to the use of any single formulae in determining rates."[32]

A closely related and equally complex regulatory standard is whether resulting rates are "just and reasonable." Phillips explains:

> [D]iscrimination is accepted in the rate structures of public utilities, but. . . such discrimination must be "just and reasonable." Discrimination is both unintentional and purposeful. It is unintentional in that some discrimination results from the efforts of utilities and commissions to simplify the rate structures by grouping customers into a limited number of classifications. It is purposeful in that discrimination may be the only way in which service can be provided to some customers. Low-density routes may be subsidized by high-density routes (even

[31] Phillips (1993), 69-70.
[32] Richard J. Pierce, *Economic Regulation: Cases and Materials* (Cincinnati: Anderson Publishing Co., 1994), 122.

> under competition), small towns by large cities. Rather than preventing discrimination, regulation merely seeks to control what discrimination takes place.[33]

In sum, regulatory agencies have considerable discretionary authority, and have exercised that authority, to determine whether rates and rate structures are within acceptable boundaries. Many state public utility commissions have found that rate consolidation by multi-system water utilities is within these boundaries.

Pricing in Practice

Despite the hallowed status of economic efficiency in ratemaking, pricing in practice often violates pricing in theory. Many sources of distortion (governmental grants and subsidies, differences in ownership, ill-defined markets for alternative water uses, and a variety of past public policies) distort price signals for water. The considerable "noise" in the real world of assigning monetary values to water undermines the efficiency of the price signal sent by utilities. Practical applications of marginal-cost pricing, when used at all, deviate substantially from the theoretical construct. One key reason is that strict adherence to the marginal-cost model could allow utility monopolies to receive excess revenues and earn excess profits (in the case of investor-owned utilities).

Averaging costs to one degree or another is an accepted practice in utility ratemaking. For example, rate regulators generally do not accept "vintage" rates that distinguish "old" customers from "new" customers even though old and new customers impose different costs on the utility system.[34] Ratemaking also tends to ignore the reality that older and newer parts of a water system will require capital investments at different times and at different costs; these improvement costs instead are averaged across the entire system and all of the utility's customers.[35]

In rate design, economic theory often gives way—at least somewhat—to practical and public policy concerns. An example that has some relevance for the single-tariff pricing debate is the provision of budget-payment plans for customers that equalize payments over a year, making the utility bill during the peak period of use (such as the winter heating bill or the summer cooling bill) more affordable. A disadvantage of the budget plan in terms of economic efficiency is that it undermines the price signal to customers, which may lead them to overconsume (and pay a higher annual bill than they otherwise would pay). But the advantages of convenience and affordability for customers, as well as avoidance of costly and potentially dangerous disconnections, generally outweigh these theoretical considerations.

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[33] Phillips (1993), 70, footnotes omitted.
[34] John Guastella, "Single Tariff Pricing and Conservation Rates," a discussion paper prepared for the Rates and Revenue Committee of the National Association of Water Companies (1994).
[35] Guastella (1994).

The budget-payment plan is an imperfect analogy to single-tariff pricing, however, in that it is customer-specific and does not involve subsidization from one customer to another. Subsidization will occur, however, with lifeline rates that provide a minimal block of usage at a price below the cost of service and lenient disconnection practices. Such policies introduce equity and fairness considerations beyond those narrowly defined by economic theory.

4. Structural Issues in the Water Industry

The U.S. water industry is complex and diverse. The U.S. Environmental Protection Agency and the state primacy agencies, count noncommunity and community water systems. According to the EPA's *Community Water System Survey* (1997), about 50,289 community water systems operate in the United States. A community water system is a system serving a population of 25 or more people with at least 15 service connections.

The data confirm both the large number of water systems in the United States, as well as the large proportion of smaller systems within that total. Relatively small systems, defined as systems serving communities with a population under 3,300 persons, comprise about 85 percent of total systems and provide water to approximately 12 percent of the connections served by community systems. Conversely, about 15 percent of community water systems are larger in size and provide water to approximately 88 percent of connections.

Systems v. Utilities

Community water *systems,* which the EPA inventories, can be distinguished from water *utilities.* Water utilities are governmental, nonprofit, or private corporate entities engaged in providing water service to one or more service territories. Water *utilities* can operate more than one water *system.* Multi-system utilities are particularly apparent in the private segment of the water industry. Many of the larger investor-owned utilities actually operated several distinct water systems. In some cases, none of the systems operated by the utility are physically interconnected; in other cases, two or more of the systems may be connected to common water source, transmission, or treatment facilities.

The state public utility commissions typically count the number of regulated water *utilities* but not necessarily water *systems.* In 1995, the number of commission-regulated water *utilities* was about 8,537 and the number of commission-regulated water *systems* was about 11,064.[36] Thus, the commissions regulate approximately 20 percent of all water systems, although the number and percentage of commission-regulated systems probably is somewhat underestimated because of the difficulty in counting regulated systems.

In some states, the number of regulated utilities is equivalent to the number of regulated systems. However, the distinction between utilities and systems is important in that many jurisdictional water utilities encompass multiple community water systems. The presence of numerous multi-system utilities is, and will continue to be, an important feature of the U.S. water industry.

[36] Janice A. Beecher, *1995 Inventory of Commission-Regulated Water and Wastewater Utilities.* (Indianapolis, IN: Center for Urban Policy and the Environment, 1995).

Multi-System Water Utilities

A multi-system water utility is a utility comprised of several distinct water systems. Physical interconnection among systems can help utilities achieve economies of scale in production and enhance service reliability. Common management of physically separate systems, however, also can help systems realize operational, management, and financing (cost-of-capital) savings.

Even without physical interconnection, the utility still can achieve economies of scale and scope through certain operational and administrative functions. Operating multiple noninterconnected systems within close physical proximity, for example, might allow the utility to save labor costs by using a circuit rider approach to system operations. A specialized maintenance team might also be used to address ongoing programs for maintenance, replacements, and improvements. Shared operations and management also can enhance the ability of water systems to respond to water emergencies. Consolidated meter reading, billing, and customer relations functions also can produce savings.

At the management level, planning, financing, regulatory relations, and other areas of decisionmaking can be consolidated on a utility-wide basis. Managers with greater expertise can be retained at the utility level than at the smaller system level. While managers with greater expertise will command higher salary and benefit packages, the investment in their expertise can yield savings that individual systems could not otherwise achieve. Ample anecdotal evidence supports the assertion that smaller systems benefit from access to expert technical knowledge. Using this expertise, multi-system utilities can exploit efficiencies and improve effectiveness by deploying a unified workforce, rather than having each individual utility maintain separate capability for various utility functions.

The potential advantages of utility-wide management may extend beyond the immediate efficiency payoffs. Planning for multiple systems, as compared to individual systems, allows for a more comprehensive approach. Better planning, in turn, should enhance the utility's capacity to respond to regional economic and environmental issues. Effective watershed management and source-water protection programs, for example, require a regional perspective that is not easily achieved by isolated systems.

Another appreciable benefit of common management is lowering the cost of capital. A consolidated utility with a broader customer and revenue base is expected to pay lower financing costs than individualized systems. This is a particularly important benefit for very small water systems.

Multi-system utility operations can be linked to the broader and more long-term policy concerns related to structural change in the water industry through regionalization. Multi-system utilities generally serve regional areas. Many have the potential to combine operations, with or without physical interconnection, with other nearby water systems (many of which are small in size). Water utility mergers and acquisitions reflect a very gradual trend toward regionalization and, in some cases, privatization of water services.

Existing utilities also can be used to provide service as an alternative to the creation of new water utilities. Indeed, many states will not certify a new water system if service from an existing provider is feasible. In addition to expanding regional water operations, some water utilities have diversified by entering the wastewater industry. Likewise, some private energy utilities providing electricity and natural gas have ventured into the water business. The formation and expansion of multi-system utilities and multi-sector utilities are part of potentially fundamental structural changes occurring in the water industry.

Pricing and Structural Change

Pricing is intrinsically related to structural change in the water industry. For example, a utility's level of interest in a merger or acquisition opportunity may depend on anticipated price effects. A negotiated sale of a utility might include limitations on near-term pricing practices or even price caps or freezes for a fixed period of time. Larger utilities often are reluctant to consider acquiring smaller, nonviable systems unless reliable means of cost recovery can be identified and secured. An acquisition candidate often presents substantial infrastructure needs but its service community lacks the ability to pay for improvements through higher rates. As mentioned already, the acquisition will yield some economies but not usually economies of a magnitude great enough to offset the diseconomies associated with the smaller system's operations. Some argue that more acquisitions would occur if acquiring companies were provided incentives, including the ability to spread costs throughout the utility's multiple service territories.

Although the dilemmas of small water systems have been extensively studied, the issue of pricing probably has received considerably less attention than viability assessment, capacity building, and related approaches. Pricing policies ultimately will play a role in shaping the future structure of the water industry, including but not limited to the future of small water systems.

Incentives for Restructuring

Single-tariff pricing has the potential to encourage economic industry consolidation and regionalization, as well as privatization.[37] Averaging costs mitigates rate shock for customers and enhances revenue stability for utilities; it also is relatively simple to administer. Some investor-owned utilities have sought rate equalization in direct connection with small system acquisitions.[38] According to one industry representative,

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[37] Janice A. Beecher, G. Richard Dreese and John D. Stanford, *Regulatory Implications of Water and Wastewater Utility Privatization* (Columbus, OH: The National Regulatory Research Institute, 1995), 141.
[38] Patrick Mann, G. Richard Dreese, and Miriam A. Tucker, *Commission Regulation of Small Water Utilities: Mergers and Acquisitions* (Columbus, OH: The National Regulatory Research Institute, 1986); Raymond W. Lawton and Vivian Witkind Davis, *Commission Regulation of Small Water Utilities: Some Issues and Solutions* (Columbus, OH: The National Regulatory Research Institute, 1983).

single-tariff pricing "could help solve the dilemma of other nonintegrated small water systems."[39]

The focus of this report is on single-tariff pricing by regulated investor-owned utilities because the issue has emerged primarily within these parameters. Rate consolidation can be used as easily by publicly owned utilities as by investor-owned utilities.[40] Many of the larger metropolitan water systems could acquire numerous contiguous small systems and employ single-tariff pricing with a negligible customer-bill impact.[41] In the context of public utility regulation and mandated takeovers, it appears that the burden of acquiring troubled systems seems has fallen more to privately owned than to publicly owned water utilities. This is because many small systems are privately owned and regulated, the larger investor-owned systems do not confine their service territories to local political boundaries and regulators can provide acquisition incentives to jurisdictional utilities. In the few states where a takeover can be mandated, it may be easier to impose this responsibility on a private system.

Unfortunately, little systematic evidence on the use of single-tariff pricing in the public sector is available. Also, most municipal utilities and many public authorities appear to operate single water systems only. However, one example of the use of single tariff pricing in the nonprofit context can be found in Clark County, Washington. Clark Public Utilities is a customer-owned district that provides water service (and other services) to 24,000 customers throughout Clark County and also operates several small "satellite" systems for small groups of homes throughout the county.[42] All customers pay the same monthly customer charge and uniform volume rate.

Some municipalities do impose zonal rates that reflect differences in elevation and pumping costs. Generally, however, municipal water utilities impose a single pricing structure for all citizen-ratepayers served within municipal boundaries; ratepayers outside of municipal boundaries often pay a higher rate.[43] Higher "outside" rates are justified on the grounds that "inside" customers bear more risks and burdens associated with financing capital improvements through municipal funding instruments. However, the rate differential often appears to be somewhat arbitrary. In a few states, charging a different rate to outside customers can trigger economic regulation by the state (Pennsylvania is an example).

Some insights can be gained from two states where state economic regulation applies both the privately and publicly owned water systems. In Wisconsin, state law *mandates* single-

[39] Edward M. Limbach, "Single Tariff Pricing," *Journal American Water Works Association* 75 no. 9 (September 1984): 52.
[40] Limbach (1984).
[41] Cities may lack adequate incentives or opportunities or acquisitions. In contrast, regulatory agencies can offer investor-owned utilities with rate-of-return and other incentives. Some commissions have the authority to mandate takeovers of smaller, nonviable water systems.
[42] Clark Public Utilities (http://clarkpud.com/Default.htm).
[43] The interest of many investor-owned utilities in single-tariff pricing clearly stands in contrast to the apparent interest of many municipally owned utilities in spatially differentiated pricing.

tariff pricing for municipalities.[44] In West Virginia, where economic regulation applies to public service districts, as well as investor-owned utilities, single-tariff pricing has been an issue because of the needs of the state's rural areas. Single-tariff pricing is approved on a case-by-case basis and both single tariffs and multiple tariffs are used throughout the state.

Many of the state commissions have broadly supported the idea of consolidating water utilities and specifically approved valuation, costing, and pricing practices that encourage larger and healthier utilities to acquire smaller and less healthy utilities. The Pennsylvania Public Utility Commission, in its policy statement regarding acquisitions, explicitly mentions single-tariff pricing. These regulatory policies are being adopted within the larger context of structural change in the water industry. These structural changes may include reconsideration of traditional methods of regulation and ratemaking, as is taking place in many jurisdictions for the other utility industries.[45]

[44] Wisconsin S. 66.069 (1) (a) (1971).

[45] In the increasingly competitive electric and natural gas industries, for example, the interest in regulatory alternatives is high. These alternatives include price caps and flexible rates, which essentially deregulate rate design by giving utilities greater discretion in setting rates within broad parameters.

5. Cost Profile of the Water Industry

Water utilities remain one of the more tried and true monopolies in terms of basic economic characteristics. In general, water service can be provided efficiently by a vertically integrated supplier; two or more suppliers (or redundant distribution systems) in the same service area would greatly increase costs and rates. The technology of water supply clearly demonstrates economies of scale, meaning that average unit costs decrease with the quantity of water provided. The prevalence of many small utilities undermines the industries' overall efficiency in terms of achieving economies of scale.

Even in comparison to other fixed utilities, water utilities require substantial investment in fixed assets relative to the variable costs of production (including the cost of raw water, energy, and treatment chemicals).[46] Using the standard of capital investment per revenue dollar, water supply is among the most capital-intensive of all utility sectors. Capital investment in water supply mainly is a function of the need to establish production capacity; maintain a complex storage, transmission, and distribution network; and meet both fire-protection specifications and peak demands. In general, the water supply industry has high fixed costs and low capital-turnover rates. However, the capital intensity of the water supply industry also can be explained by the industry's relatively low variable (operating) costs, which translate into relatively low operating revenues.

Reflecting these cost characteristics, water rates typically take the form of a fixed charge that does not vary with usage and a variable charge that varies with usage. Traditional cost-of-service principles can lead to very high fixed charges and very low variable charges for water utilities. Efficiency-oriented rates, however, tend to accentuate the variable component of the water bill in order to affect consumption behavior.

Trends in Water Costs

Water supply clearly is a *rising-cost* industry. Water supply utilities, and their regulators at the federal, state, and local levels, are increasingly aware of the water supply industry's changing revenue requirements. Three key forces affecting the industry's costs are (1) the need to comply with regulatory provisions of the Safe Drinking Water Act (SDWA), (2) the need to replace and upgrade an aging water delivery infrastructure, and (3) the need to meet population growth and promote economic development. In addition, water utilities face a variety of secondary cost forces. These include the often high cost of borrowing to finance capital projects (especially for small systems) and the shift to nonsubsidized, self-sustaining operations (especially for publicly owned systems).

[46] For a comparison of the water industry to the electric, natural gas, and telecommunications industries, see Janice A. Beecher, *The Water Industry Compared: Structural, Regulatory, and Strategic Issues for Utilities in a Changing Context* (Washington, DC: National Association of Water Companies, 1998).

The concurrent and mutually reinforcing impact of these forces on many water utilities presents a substantial pressure on both capital and operating costs, a pressure not previously experienced by the water supply industry. In response, water utilities are reexamining their cost allocation and rate design practices. The interest in alternative ratemaking methods for the water sector is on the rise.

Rising costs, along with structural and regulatory changes in this industry is placing new demands on utility regulators. However, rising costs should not be taken for granted but closely scrutinized. Moreover, the water supply industry must be held accountable for making prudent decisions in response to its changing cost profile. The industry must be able to fully justify the use of alternative approaches to meeting revenue requirements (including automatic cost-adjustment mechanisms, pass-throughs, and special surcharges, as well as cost-allocation and rate-design methods).

Water utility regulators generally are open to the consideration of policy alternatives but also vigilant about whether these alternatives are within the scope of regulatory authority and consistent with accepted regulatory principles. Regulators will want to be especially cautious about affecting the incentives that determine whether utility costs are effectively managed. Thus, the industry perspective on rising costs and how to address them should be tempered by a reasoned regulatory perspective.

Economies of Scale

Although an arbitrary threshold, water systems serving under 3,300 (or approximately 1,000 service connections) generally lack economies of scale in production and other aspects of service.[47] As a result, many small water systems are prone to capacity problems and difficult to sustain over time.

Economies of scale in water supply, particularly in the areas of source development and treatment, make it difficult for smaller water utilities to perform as well as larger water utilities. Declining unit costs of production indicate scale economies; as the volume of water "produced" (that is, withdrawn and treated) increases, the cost per gallon or cubic foot decreases. At lower unit costs, production is less costly in the aggregate and more efficient at the margin.

Very small water systems underperform primarily because they simply are not large enough to achieve economics of scale. Scale economies in the water sector explain why smaller utilities tend to have less capacity in financial, managerial, and technical terms.[48] Rising

[47] U.S. Environmental Protection Agency, *Affordability of the 1986 SDWA Amendments to Community Water Systems* (Washington, DC: U.S. Environmental Protection Agency, 1993).
[48] Janice A. Beecher, G. Richard Dreese, and James R. Landers. *Viability Policies and Assessment Methods for Water Utilities* (Columbus, OH: The National Regulatory Research Institute, 1992).

costs over the past decade have exacerbated the condition of smaller systems.[49] Capacity-development problems often are manifested in higher rates for water service.

Scale economies (or lack thereof), thus become an important determinant of how much people pay for water service. As a generalization, assuming comparable system characteristics and cost-based pricing, larger systems should be able to provide service at a lower price than smaller systems. In reality, of course, many factors other than system size (such as the quality of source water and treatment methods required) influence ultimate water costs and prices. But as a generalization, it is widely held that smaller water systems must charge customers much higher rates for water service comparable to service provided by larger water systems.

Importantly, the economies of scale in water production are associated with the *volume* of water produced (not simply the number of service connections). Even smaller systems that are fortunate enough to have one or two large-volume customers will enjoy some economies of scale. Two utilities can have a comparable level of investment per customer and cost-of-service for the same number of residential customers, but if one also serves a large industrial firm and economies of scale are achieved, everyone in that community will enjoy lower water bills. In other words, when *controlling* for large-volume use, the level of investment and the cost of service can be quite comparable from system to system. One of the arguments in favor of single-tariff pricing is that it allows all customers to benefit from the location of large customers anywhere in the composite service territory.[50]

Some evidence about the effect of utility size on water prices is available. A 1996 survey, summarized in Table 4, found that median prices decline as system size increases for different classes of customers served (residential, commercial, and industrial). The implication is that small-systems customers pay more for roughly the same level of service as large-system customers. As a consequence, the affordability of water service is a greater threat for small systems. "Rate shock" is another problem for many smaller systems because increasing costs must be spread over a smaller customer base.

In some respects, rate consolidation is similar to "aggregation," a tool emerging in the context of electric industry restructuring. Aggregation is used to group customers according to similar characteristics, usage patterns, or service requirements. Aggregation can provide access to services and a degree of purchasing power to disadvantaged customers. In effect, multi-system utilities are aggregators for the customers in the various systems they manage. Both aggregation and rate consolidation can promote the broader goal of universal service.

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[49] Janice A. Beecher, Patrick C. Mann, and John D. Stanford, *Meeting Water Utility Revenue Requirements* (Columbus, OH: The National Regulatory Research Institute, 1993).

[50] Conversely, large-volume users in the larger service territory might complain that single-tariff pricing forces them to subsidize customers in outlying areas.

Table 4
Monthly Water Bills by System Size and Customer Class

Customer Class	Group A Systems Producing >75 MGD *(n=34)*	Group B Systems Producing 15 to 75 MGD *(n=61)*	Group C Systems Producing < 15 MGD *(n=47)*
Residential			
Median monthly charge for 1,000 cubic feet (7,480 gallons)	$13.19	$14.64	$15.61
Commercial			
Median monthly charge for 50,000 cubic feet (374,000 gallons)	$486.82	$530.92	$578.96
Industrial			
Median monthly charge for 1,000,000 cubic feet (7,480,000 gallons)	$7,926.97	$8,747.06	$10,292.34

Source: Raftelis Environmental Consulting Group, *1996 Water and Wastewater Rate Survey* (Charlotte, NC: Raftelis Environmental Consulting Group, 1996), Exhibit 2.
MGD = million gallons daily. *n* = number of systems in the sample.

Capacity Development

Federal policymakers and state regulators, including both drinking water primacy agencies and public utility commissions, have long been concerned about how to check the emergence of new nonviable water systems, how to improve the performance capacity of existing systems, and how to maintain safe and affordable water service.[51] The 1986 Safe Drinking Water Act triggered substantial attention to small-system issues and the problem of keeping rates affordable in light of the newly enacted standards.

Regulators continue to seek out ways to balance the equally legitimate fiscal concerns of water utilities (that is, financial capacity) and utility customers (that is, affordability). The 1996 Safe Drinking Water Act codified capacity-development policies for new and existing water systems and elevated the capacity-affordability conundrum to a higher place on the policy agenda.

Capacity in this context is defined in terms of a utility's financial, managerial, and technical well being. Financial capacity carries particular importance because a financially healthy utility will have the resources needed for professional management and technically appropriate operations. Many (but not all) small water systems struggle with significant capacity problems. These problems are manifested by the small water utility's poor performance in many areas, including regulatory compliance.

[51] Beecher, Dreese, and Landers (1992).

Traditionally, both economic and public health regulators have been very focused on small-system capacity issues. Policymakers have paid considerable attention to smaller water systems and the tradeoffs between ensuring a financially healthy system and maintaining affordable rates for safe and reliable water service. One manifestation of capacity problems is noncompliance with drinking water standards. For small systems, these violations often include failure to meet monitoring and reporting requirements. Small systems also have difficulty complying with public utility commission regulations. For very small systems, meeting the procedural mandates of economic regulation (such as rate filing requirements) can be difficult.

Small water systems have long troubled state economic regulators. Many (but certainly not all) of the commission-regulated water systems are small in size, which poses certain public policy problems. Particularly problematic are the very small systems that were the product of unchecked real estate development and lax local zoning policies. Many of these systems are geographically isolated, which often precludes interconnection with another system. Lacking economies of scale, smaller water systems typically must charge a much higher rate for service than larger systems. Higher rates make water service less affordable for customers of smaller water systems.

As a utility monopoly, water supply demonstrates substantial economies of scale. Larger water systems enjoy these economies, meaning that they can spread certain costs over a larger customer base. Lower production costs are reflected in lower prices to customers. Smaller systems must recover revenue requirements over a smaller customer base. In general, smaller systems are more likely to encounter capacity and affordability problems.

Consumer Affordability

Economic theory argues strongly for cost-based utility rates, that is, rates based on the true cost of providing a service. An efficient (cost-based) rate should sustain the water system; however, if the rate is unaffordable to the service population and customers cease to pay for and/or receive the service, the water system itself may cease to exist. This solution may achieve a degree of economic efficiency, while sacrificing other fundamental public health, safety, and quality-of-life purposes.

For many water customers, the affordability of water service is a growing problem. The problem of affordability affects customers in terms of increased arrearages, late payments, disconnection notices, and actual service terminations. Affordability affects utilities in terms of expenses associated with credit, collection, and disconnection activities; revenue stability and working capital needs, and bad debt or uncollectible accounts that other customers must cover.

Other ramifications of the affordability issue also are becoming apparent. If a customer base cannot support the cost of water service, potential lenders may be concerned about the utility's financial health and ability to meet debt obligations. Moreover, disconnecting

residential water customers can present a public relations nightmare for utilities, particularly because essential services are involved. Increasingly, problems of bad debt also extend to nonresidential utility customers. Financial distress and bankruptcies in the commercial and industrial sectors can leave utilities holding the bag. However, the larger issue of affordability is primarily a concern with respect to low-income residential consumers.

For low-income customers, who have little choice but to buy service from the local utility, paying more for basic water service means going without less essential and more discretionary products and services. Thus, rising water prices can contribute to deterioration in the quality of life for low-income utility customers. While larger systems can spread the cost of providing assistance to low-income customers, a small system with an impoverished customer base has no opportunities for even limited subsidization.

6. Examples of Single-Tariff Pricing

All utility pricing involves some form of *averaging.* Utility systems do not establish a rate for Customer A based on the cost of serving Customer A, a rate for Customer B based on serving Customer B, and so on. Doing so might be considered efficient and equitable, but it also would be extraordinarily costly from an administrative standpoint (that is, the transaction costs would be astronomical). Instead, utility systems tend to group customers into customer classes—residential, commercial, and industrial—based on similarities in the cost of serving customers in those categories. Occasionally, a unique customer (often a large-volume customer, such as a food-processing plant) might be able to negotiate a special rate based on unique cost-of-service characteristics, but most customers pay a rate based on cost averaging.

Basic Single-Tariff Pricing

Single-tariff pricing basically is the conceptual "opposite" of zonal or spatially differentiated pricing. Single-tariff pricing suggests that ratemakers should de-emphasize spatial differences in costs; costs are aggregated rather than disaggregated. One of the chief advantages of single-tariff pricing, from the utility's standpoint, is simplification. Single-tariff pricing does not negate the need to determine the revenue requirement and to allocate the revenue requirement among customer classes. It may still be necessary for the utility to maintain cost data for separate facilities and services in accordance with accepted accounting practices and regulatory reporting standards. Once revenue requirements are established, however, the *allocation* process is greatly simplified because it is unnecessary to spatially allocate common costs (that is, costs that are not site-specific). Total costs simply are spread over the consolidated customer base and only one rate is designed for each class of customers or service.

A sample calculation of a single-tariff price is provided in Table 5. In this very simple illustration, the cost of service and total water sales are varied for three separate service territories (A, B, and C). A relatively modest amount of water usage (5,000 gallons per month or 60,000 gallons per year) is assumed. The number of residential connections and the annual cost of service are varied to reflect differences in costs and economies of scale. For simplicity, only residential customers are considered.

Service Territory A is in the most favorable position, in terms of economies of scale (number of customers and sales volume); Service Territory C is in the least favorable position, which accounts for the higher costs per connection and per sales. A stand-alone tariff results in a cost of service equivalent to $1.94, $2.08, and $2.78 per 1,000 gallons of water service in the three respective service territories. The transition to single-tariff pricing would result in a rate of $2.11 per 1,000 gallons for all customers in all three service territories.

The illustration reveals the resulting shift in cost responsibility from the customers in the larger Service Territory A to the smaller Service Territory C. However, the *decrease* in rates to customers in Service Territory C of 67 cents per 1,000 gallons (24.1%) is offset

Table 5
Sample Calculation of Single-Tariff Pricing

Service Territory A		
Total residential connections		6,000
Total annual water use per connection		60,000
Total annual water sales (gallons)		360,000,000
Total annual cost of service		700,000
Annual cost per connection		$116.67
Cost per 1,000 gallons sold		$1.94
Service Territory B		
Total residential connections		2,000
Total annual water use per connection		60,000
Total annual water sales (gallons)		120,000,000
Total annual cost of service		250,000
Annual cost per connection		$125.00
Cost per 1,000 gallons sold		$2.08
Service Territory C		
Total residential connections		1,500
Total annual water use per connection		60,000
Total annual water sales (gallons)		90,000,000
Total annual cost of service		250,000
Annual cost per connection		$166.67
Cost per 1,000 gallons sold		$2.78
Combined Service Territory		
Total residential connections		9,500
Total annual water use per connection		60,000
Total annual water sales (gallons)		570,000,000
Total annual cost of service		1,200,000
Annual cost per connection		$126.32
Cost per 1,000 gallons sold		$2.11
Rate Impact of Single Tariff	**Per 1,000 Gallons**	**Percentage Change**
Service Territory A	+17 cents	+8.8%
Service Territory B	+3 cents	+1.4%
Service Territory C	-67 cents	-24.1%

Source: Author's construct. For simplicity, only residential customers are considered and a price-elasticity adjustment (that is, a usage response to the change in price) is not included in the illustration.

primarily by the relatively smaller *increase* in rates to customers in Service Territory A of 17 cents per 1,000 gallons (8.8%). The larger number of customers in Service Territory A lessens the impact of the rate adjustment on a per customer basis. Customers in Service Territory B are least affected, experiencing an increase of 3 cents per 1,000 gallons (1.4%) in rates. The lower cost-of-service in Service Territory B (relative to the number of connections served) in comparison to Service Territory C accounts for the difference in the rate impact.

In practice, rate design for public utilities is far more complex.[52] (See Appendix C.) Utilities must analyze the cost of service, including the cost of capital, and determine revenue requirements for the period over which rates will be set (the "test year"). A utility's costs will be allocated according to customer groups (or classes) and the demand characteristics of those groups. Typically, residential customers are distinguished from nonresidential customers, the latter of which are further divided into commercial and industrial classes.

Variations of Single-Tariff Pricing

Utility tariffs, or rate structures, actually have various components. These components make it possible for utilities to approach single-tariff pricing in different ways depending on system cost characteristics and the nature of the current rate structure. Table 6 illustrates three variations. In the first, uniformity is established only for the fixed charge portion of the utility bill. In the second variation, fixed charges vary and uniformity is established for the variable portion of the utility bill. The third variation is the more complete example of single-tariff pricing, where both fixed and variable charges are made uniform.

These variations can be used to phase-in single-tariff pricing over time, as illustrated in Table 7. A phase-in plan reflects the principle of gradualism in ratemaking. A significant change in rate levels or rate design can be implemented in phases, rather than at once, in order to reduce rate shock to customers and revenue instability to the utility. In this example, the utility first consolidates fixed charges and gradually consolidates the variable rate. Many utilities have used a phased approach to implementing single-tariff pricing, with the encouragement and approval of regulators.

At least three other variations of single-tariff pricing can be identified. First the utility can retain current rate differentials and equalize future rate increases. This addresses the rate shock issue while maintaining rate differences based on historical differences in costs. Second, the utility can use rate "bands" to establish tariffs for groups of systems with similar cost characteristics. Third, the utility can combine rate equalization with the strategic use of short-term or mid-term surcharges to pay for extraordinary costs associated with blending the operations of multiple systems. Each of these methods has been implemented on at least one occasion.

[52] Beecher and Mann (1990).

Because of rising costs, and the need for rate customers to gradually become accustomed to higher rates, it may not be desirable to lower rates at all for any customer group. Rather, it may be advisable to "cap" higher rates in the higher-cost areas and gradually increase rates in the lower cost areas. Although customers should be educated about changes in the rate structure, a phased approach and a price-cap approach might help mitigate complaints about cost shifting.

Table 6
Pricing Variations for Fixed and Variable Water Charges

	Before Implementation		After Implementation	
	Fixed Charge	**Variable Rate**	**Fixed Charge**	**Variable Rate**
Variation 1: Change to Single Fixed Charge Only				
Service Territory A	$6.00 per month	$1.95 per 1,000 gallons	$7.50 per month	$1.95 per 1,000 gallons
Service Territory B	$9.00 per month	$2.15 per 1,000 gallons	$7.50 per month	$2.15 per 1,000 gallons
Variation 2: Change to Single Variable Rate Only				
Service Territory A	$6.00 per month	$1.95 per 1,000 gallons	$6.00 per month	$2.05 per 1,000 gallons
Service Territory B	$9.00 per month	$2.15 per 1,000 gallons	$9.00 per month	$2.05 per 1,000 gallons
Variation 3: Change to Single Tariff for Fixed Charges and Variable Rates				
Service Territory A	$6.00 per month	$1.95 per 1,000 gallons	$7.50 per month	$2.05 per 1,000 gallons
Service Territory B	$9.00 per month	$2.15 per 1,000 gallons	$7.50 per month	$2.05 per 1,000 gallons

Source: Author's construct.

Table 7
Phase-In Approach to Single-Tariff Pricing

	Before Implementation		After Implementation	
	Fixed Charge	Variable Rate	Fixed Charge	Variable Rate
Phase 1: Change to Single Fixed Charge				
Service Territory A	$6.00 per month	$1.95 per 1,000 gallons	$7.50 per month	$1.95 per 1,000 gallons
Service Territory B	$9.00 per month	$2.15 per 1,000 gallons	$7.50 per month	$2.15 per 1,000 gallons
Phase 2: Adjust Variable Rates				
Service Territory A	$7.50 per month	$1.95 per 1,000 gallons	$7.50 per month	$2.00 per 1,000 gallons
Service Territory B	$7.50 per month	$2.15 per 1,000 gallons	$7.50 per month	$2.10 per 1,000 gallons
Phase 3: Equalize Variable Rates				
Service Territory A	$7.50 per month	$2.00 per 1,000 gallons	$7.50 per month	$2.05 per 1,000 gallons
Service Territory B	$7.50 per month	$2.10 per 1,000 gallons	$7.50 per month	$2.05 per 1,000 gallons

Source: Author's construct.

Two Recent Cases

In 1997, the Indiana Utility Regulatory Commission approved a hard-won plan by the Indiana-American Water Company to consolidate rates. Figure 6 illustrates the difference in revenue requirements per equivalent residential customer for stand-alone pricing, common-management pricing, and single-tariff pricing.[53] Stand-alone pricing reflects the costs that a commonly owned or managed water system would incur if it replicated the same services and functions on a basis completely independent of the parent utility and other systems. Common-management pricing reflects costs that are incurred on the basis of the joint operation of multiple systems. Costs under common management, given management economies of scale and scope, should be less for the utility than the sum of stand-alone costs for all of the operated systems.

[53] In this illustration of single-tariff pricing, the use of equivalent customers produces a comparable but not identical level of revenues per customer across all service territories because of differences in water usage.

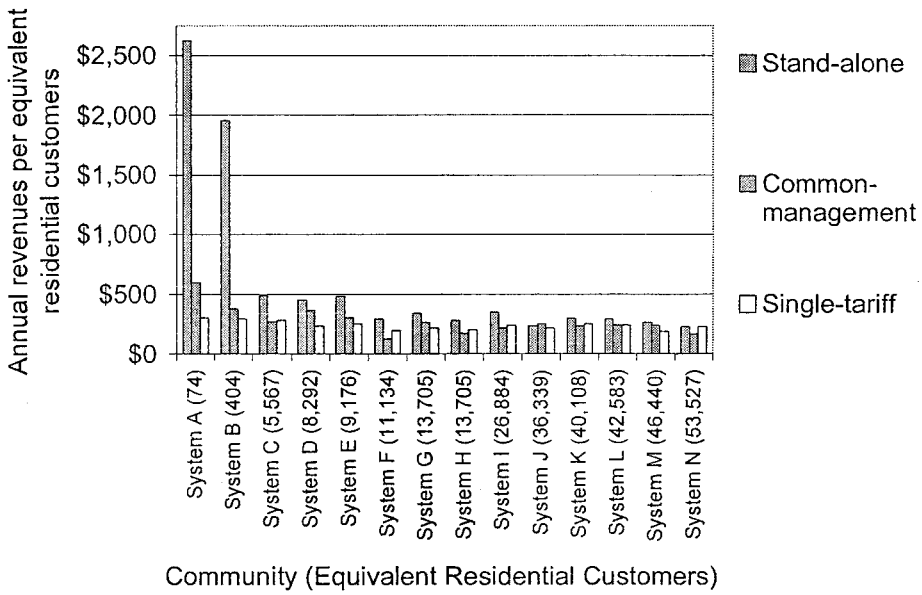


Figure 6. Revenue Requirements per Equivalent Residential Customers for Stand-Alone Costs, Common-Management Costs, and Single-Tariff Pricing

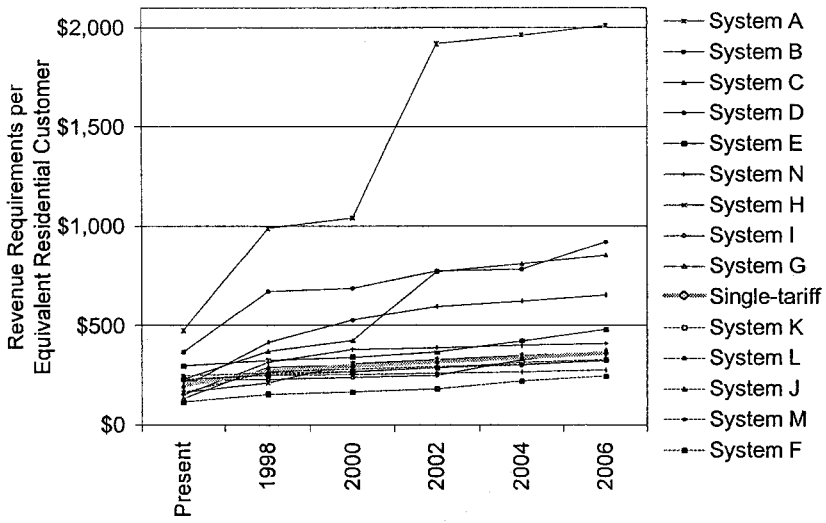


Figure 7. Forecast Revenue Requirements per Equivalent Residential Customers Including Capital Improvements

Source: John F. Guastella, Testimony in Cause No. 40703 before the Indiana Utilities Regulatory Commission, Indiana-American Water Company (1997), Exhibits JFG-5, JFG-R-1, and JFG-R-3.

For each community served, the economies of scale and scope achieved by common management are obvious. Left to their own devices, none of the communities could replicate the same level of service at the same cost. In other words, each community's true stand-alone cost would be much higher than their share of costs under consolidated operations. These cost savings are achieved independent of the pricing structure.

The additional benefits of single-tariff pricing are fairly obvious. The smaller, very high cost systems at the low end of the spectrum clearly have much to gain through rate consolidation. Both common-management and consolidated rates are a fraction of what the system would pay on a stand-alone basis. The impact of the single-tariff price on customers at the middle and higher end of the spectrum is not necessarily substantial.

The rate stabilizing effect of single-tariff pricing is illustrated by the revenue requirements forecast for the same group of utilities (Figure 7). Over time, the single-tariff provides considerable rate (and revenue) stability and, once again, the benefits for the smaller systems are clear. In this particular case, substantial rate hikes associated with planned capital improvements for four systems can be mitigated. The timing of capital expenditures will play a role in determining perceptions about the benefits of single-tariff pricing to individual communities. The obvious affordability benefits to small systems, as well as the general "smoothing" effect on revenue requirements, are among the leading rationales for single-tariff pricing.

Similar results were achieved in another recent case involving a New Hampshire utility, Pennichuck Water Works, Inc. Without rate consolidation, some water customers would face annual water bills as high as $1,200, as illustrated in Figure 8. In its decision, the New Hampshire commission directly addressed subsidy and affordability issues, as well as the anticipated benefits of adopting the single tariff:

> We do not believe it would be in the public interest to impose annual rates in the range of $800 to $1200, as would be the case here, when a reasonable alternative is available. By consolidating the community systems with the core system for ratemaking purposes, all customers would face a uniform tariff which, for the average residential customer, would be approximately $253 per year. The rates for the average residential customer in the core system would increase less than $1.00 per month, for a total of $8 per year, under the rate consolidation proposal which, in light of the alternative, we find to be acceptable. We consider a single tariff rate of approximately $253 per year for the core residential customer to be just and reasonable. A consolidated rate will ensure affordability and the continued viability of many of Pennichuck's community systems. It will also enable Pennichuck to operate in a more administratively efficient manner by eliminating separate general ledgers for each system, thereby reducing administrative costs.[54]

[54] New Hampshire Public Utilities Commission, Order in Docket DR 97-058, Pennichuck Water Works, Inc. (1998).

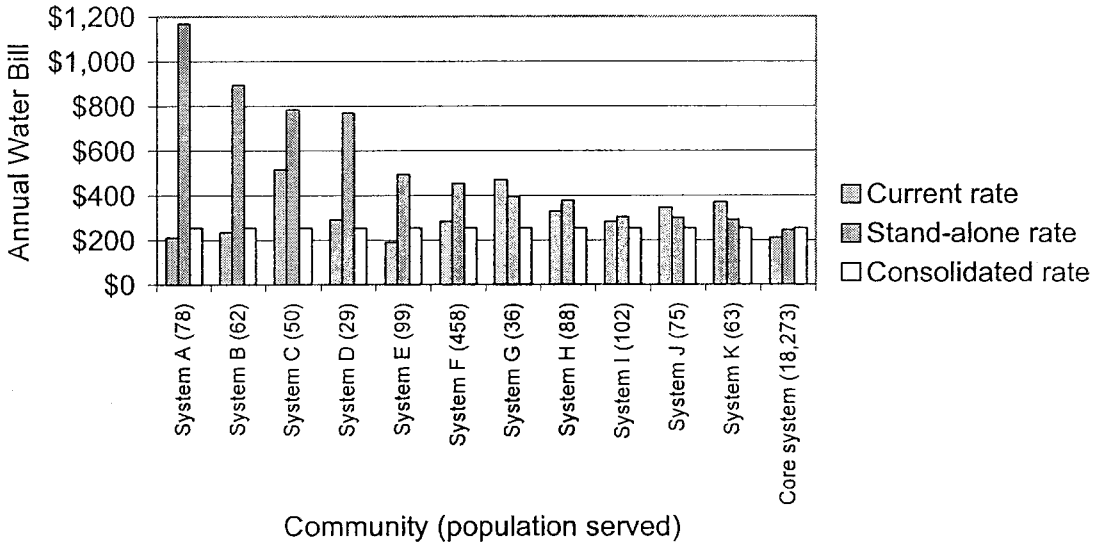


Figure 8. Stand-Alone and Consolidated Rates for Pennichuck Water, New Hampshire

Source: New Hampshire Public Utilities Commission, Order in Docket DR 97-058, Pennichuck Water Works, Inc. (1998).

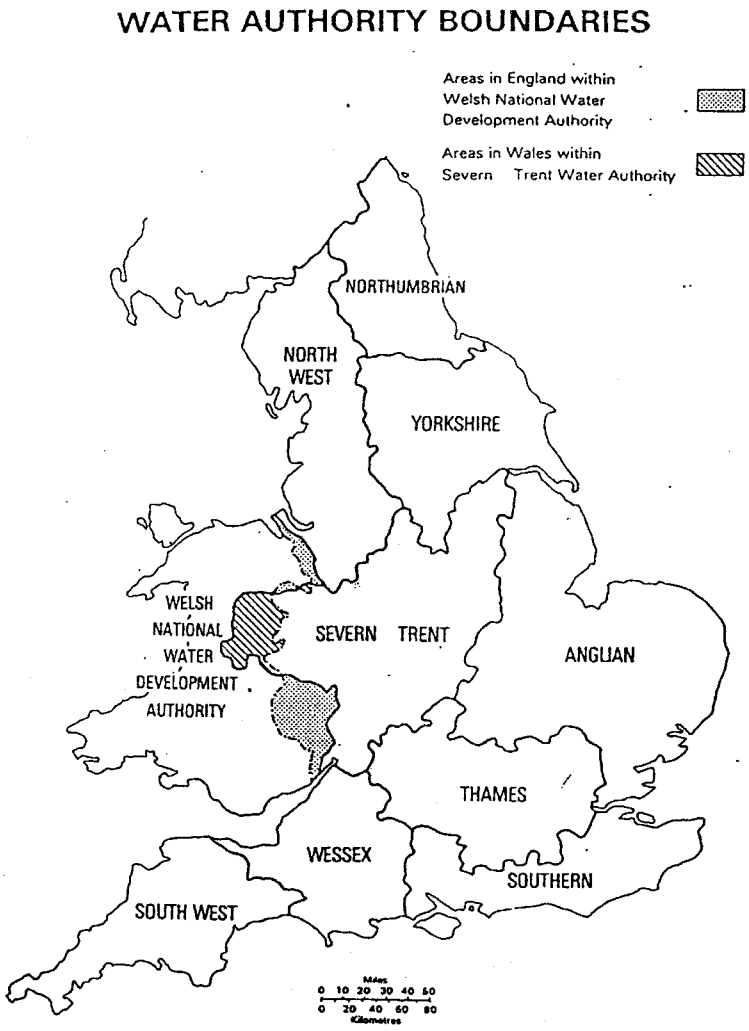
Single-Tariff Pricing in Great Britain

Great Britain provides a "real life" example of the use of single-tariff pricing on a very large scale. In 1989, Great Britain's ten large regional water, wastewater, and stormwater service providers (shown in Figure 9) were transformed from nationalized to investor-owned utilities. Since privatization, the tariffs established for *measured* (metered) service within each of the regional systems have been uniform. In other words, single-tariff pricing is implemented along with metering. Each of the water utilities provides a metering option, although a large proportion of British households is not metered. For *unmeasured* service, standing charges are uniform. However, variable charges are based not on water volumes but on the "rateable" value of properties served. These charges vary according to geographic zones for the Severn Trent and Thames water utilities, but not for the other utilities.

Tariffs for residential water service for 1995-1996 are reported in Table 8. Metered rates for large users are comprised of standing (fixed) charges that vary by meter size, plus a volumetric charge. Standing and volumetric charges are uniform for large-volume customers throughout the company service territories.

In addition to the larger privatized utilities, another twenty-one water service companies also serve somewhat smaller service territories in Great Britain, although in terms of population served almost all seem quite substantial in size when compared to many U.S. water systems. For the most part, these companies also employ single-tariff pricing. All of the twenty-one companies use a uniform standing (or fixed) charge; four have different volumetric rates for different geographic areas served.[55]

[55] For one of these companies (Three Valleys), two of three areas have comparable metered rates, suggesting a gradual move toward uniform pricing. A fifth water company (North East) adopted single-tariff pricing in the 1993-94 rate period for its two areas (each of which also is subdivided).



The ten Water Authorities in England and Wales
(reproduced by permission of the Controller of Her Majesty's Stationery Office)

Figure 9. Regional Water Utilities in Great Britain.

Source: Daniel A. Okun, *Regionalization of Water Management: A Revolution in England and Wales* (London: Applied Science Publishers, 1977).

Table 8
Metered Water Tariffs for British Water Companies, 1995-1996 (Household Customers)

Company	Service Characteristics			Tariffs for Water Service			
	Area Served	Households Served	Metered Households	Unmetered		Metered	
	km^2	(000)	(%)	Standing charge (pounds)	Rateable Value Charge	Standing charge (pounds)	Volumetric Charge p/m^3
Anglian	22,000	1,510	16.8	37.35	50.69	27.00	69.62
Dwr Cymru	20.400	1,081	2.8	81.28	38.72	33.00	75.39
North West	14,415	2,643	4.9	29.00	35.20	32.00	60.10
Northumbrian	3,850	470	0.6	52.00	27.15	31.20	53.43
Severn Trent	19,745	2,804	8.2				
Zone 1				none	45.85	27.00	62.90
Zone 2				"	41.29	"	"
Zone 3				"	40.04	"	"
Zone 4				"	41.81	"	"
Zone 5				"	48.08	"	"
Zone 6				"	50.02	"	"
Zone 7				"	50.38	"	"
Zone 8				"	40.04	"	"
East Worcester				"	41.29	"	"
South West	10.300	585	9.1	40.00	49.43	27.20	74.63
Southern	4,450	879	11.8	21.00	33.70	31.00	52.10
Thames	8,200	3,022	5.4				
Area 1				14.00	25.41	20.00	48.14
Area 2				"	25.85	"	"
Area 3				"	19.45	"	"
Area 4				"	23.29	"	"
Area 5				"	29.90	"	"
Area 6				"	25.90	"	"
Area 7				"	35.63	"	"
Wessex	7,350	435	9.7	24.00	45.45	30.50	67.78
Yorkshire	13,900	1,729	6.0	22.00	56.60	25.00	64.20

Source: Office of Water Services, *1995-96 Report on Tariff Structure and Charges* (Birmingham, UK: Office of Water Services, 1995

7. The Public Utility Commission Role

Regulation of the water industry, like the water industry itself, is fragmented and pluralistic. All community water systems, regardless of their ownership, are subject to federal and state drinking water regulations pursuant to the federal Safe Drinking Water Act. Drinking water standards focus on public health concerns. Water systems in many states also are subject to water quantity regulations, meaning that water withdrawals are regulated through registration or permitting mechanisms. Economic regulation of water utility prices and rates of return is the domain of the state public utility commissions. The commissions play a quasi-administrative, quasi-legislative, and quasi-judicial role in terms of overseeing the utility industries.

Although their jurisdiction for the water industry is not comprehensive, and generally applies only to investor-owned water systems, the state public utility commissions have specific authority and expertise in the area of pricing. Moreover, many commission-regulated systems are small in size. Thus, pricing practices in general, and commission policies in particular, are worth considering when crafting solutions for small systems.

Forty-five commissions presently have authority to regulate investor-owned water utilities. In some of the states, commission regulation extends to other types of water utilities under certain circumstances. For example, some states regulate municipal water utilities if they provide service outside of municipal boundaries. In Florida, counties can opt to regulate water systems; in Indiana, municipal water utilities can opt to be regulated. In terms of commission jurisdiction and authority, many variations among the states can be found.

Not all water utilities are subject to commission regulation. Most water utilities in the United States are publicly owned and not subject to state economic regulation. The state public utility commissions do not regulate water utilities in Georgia, Michigan, Minnesota, North Dakota, South Dakota, or Washington, D.C.

Number of Regulated Utilities

Periodic surveys have been conducted for the purpose of counting the number of regulated water and wastewater systems. As noted earlier, for 1995 the total number of commission-regulated water utilities in the United States was approximately 8,537.[56] Approximately 4,095 regulated water utilities are classified as investor-owned water utilities.[57] Table 9 summarizes the 1995 inventory of commission-regulated water and wastewater utilities.

[56] Beecher (1995).

[57] These data include 15 investor-owned utilities and 3 homeowners' associations that no longer are regulated in Michigan.

Table 9
Commission-Regulated Water and Wastewater Utilities

Utility Ownership	Water Utilities		Wastewater Utilities	
	Number of Commissions	Number of Utilities	Number of Commissions	Number of Utilities
Investor-owned or private	46	4,095	28	1,233
Municipally-owned	11	1,547	6	649
Districts	7	1,300	4	205
Cooperatives	4	1,436	2	50
Homeowners' associations	6	85	1	0
Nonprofits	1	73	1	15
Other	1	1	0	0
Totals	46	8,537	28	2,152

Source: Janice A. Beecher, *1995 Inventory of Commission-Regulated Water and Wastewater Utilities* (Indianapolis, IN: Center for Urban Policy and the Environment, 1995). Includes data for Michigan, which ceased regulating 18 systems in 1996.

Leading states in terms of the number of regulated water utilities are Texas (3,300), Mississippi (740), Wisconsin (573), West Virginia (421), Arizona (354), and New York (354). For investor-owned water utilities, leading state jurisdictions are Texas (1,200), Arizona (354), New York (334), North Carolina (226), Florida (210), California (199), and Pennsylvania (190).

Between the 1989 and 1995 surveys, the number of regulated investor-owned utilities declined by 445 utilities (10 percent); the total number of regulated utilities declined by 1,398 utilities (14 percent).

States in which the number of regulated water utilities (including investor-owned utilities) declined by a substantial amount include Arizona, Connecticut, Indiana, New York, North Carolina, Pennsylvania, and Texas. Commission sources suggest that mergers and acquisitions were the leading cause of the decline. Systems rarely cease operations altogether. However, transfers to unregulated ownership forms and changes in commission jurisdiction also can contribute to the decline in the number of regulated utilities. A few states, including Mississippi and Oregon, had substantial increases in the number of utilities under their jurisdiction. Nebraska's gain is noteworthy because jurisdiction for the water industry was initiated in 1994.

The decline in the number of regulated utilities is consistent with an anticipated trend in industry consolidation. Mergers and acquisitions within both the public and private segments of the industry will gradually reduce the number of regulated utilities. However, the population served by regulated utilities will not necessarily decline as a result of reductions in the total number of regulated utilities.

Despite the decline in the number of regulated water utilities, water utility regulation continues to rise in importance on the agendas of many state commissions.[58] Economic regulation of water utilities is important given monopoly power, rising costs, structural change, and a degree of uncertainty about the industry's future.

Capacity-Development Policies

The commissions, which are well aware of the precarious condition of many small water systems, can and have addressed capacity development through three basic strategies. The first strategy involves slowing the creation of new water systems. State regulations can create substantial barriers to entry for new water systems. Many of the state commissions, as well as the state drinking water agencies, are tightening the certification process and more carefully scrutinizing the financial, managerial, and technical competencies of proposed new systems.

The second strategy involves procedural simplification for small water systems to lower the administrative cost of regulation and enhance regulatory compliance. This strategy includes simplifying filing and reporting procedures. In some cases, commission staff members directly assist managers of small water utilities in meeting procedural requirements. Some of the commissions have used alternative regulatory methods, such as operating ratios, to further simplify the process and address the unique needs of small systems. Regulatory simplification treats one of the primary symptoms of small-system capacity problems (that is, regulatory compliance), but it does not necessarily treat the underlying capacity problem (that is, lacking economies of scale).

The third strategy involves structural change in the water supply industry. As noted in a report of the National Regulatory Research Institute, the least-cost solution to regulatory compliance and other problems for many systems can be found only through structural change, namely consolidation.[59] The downward trend in the number of water systems suggests that ownership consolidation may be occurring in the industry. Consolidated systems may or may not be physically interconnected. While physical interconnection yields significant economies of scale, common management of noninterconnected systems directly addresses financial, managerial, and technical capacity issues and can yield significant economies.

Many of the commissions have played an active role in this area by encouraging and approving mergers and acquisitions. Some of the commissions provide specific incentives, such as acquisition adjustments. Certain ratemaking practices, including single-tariff pricing, also can provide incentives for acquisitions and, perhaps, the formation of regional water systems. Larger systems interested in acquiring smaller systems tend to favor rate consolidation (sometimes with surcharges).

[58] In the late 1990s, however, water issues must compete for the attention of regulators with major restructuring issues in the energy and telecommunications sectors.
[59] Beecher, Dreese, and Landers (1992).

In general, modern public policies affecting the water-supply industry, including regulatory policies, appear to support the consideration of structural options (including consolidation) that will help water systems achieve economies of scale. The emphasis on water system capacity at the federal, state and local levels will make it harder for providers to get operating certificates, water-supply permits, and special financing. Explicitly or implicitly, growth management policies in some states are calling for consolidation of water supply through interconnection with existing systems. Public policy also appears to emphasize the importance of establishing and maintaining water systems for which the population served can support the cost of water service. Thus, institutional factors also are playing a role in reducing the number of water systems.

8. Commission Survey

State public utility staff members at all of the state public utility commissions with jurisdiction for water utilities (that is, forty-five state commissions), were surveyed about the issue of single-tariff pricing in early 1996. This research was conducted by Dr. Janice Beecher on behalf of the Florida Public Service Commission. The survey was first sent by telefax in January and follow-up telephone calls were made in late January and early February to ensure the completeness and accuracy of the survey. The commission staff members who completed the survey are knowledgeable about water utility regulation and competent to complete this particular questionnaire. A copy of the survey questionnaire is attached as Appendix D. Detailed findings can be found in Appendix E.

Additional follow-up contacts were made in 1997 and 1998 to update findings on specific cases that were pending at the time of the original survey, as well as to check for any major shifts in regulatory policy. Although no significant changes were detected, updated information is noted throughout the findings.

Relevance of Single-Tariff Pricing

Single-tariff pricing for water utilities is not necessarily a policy issue for every state public utility commission. Jurisdiction for water utilities and the presence of multi-system utilities are necessary but not sufficient conditions for consolidated rates to be an issue for a given commission. Single-tariff pricing does not become an issue until a utility or the commission initiates the use of this method. Utilities with systems that are viable on a stand-alone basis, by virtue of size and other factors, may not need or want single-tariff pricing. Even when considered or implemented, single-tariff pricing may not be considered "an issue" if it is noncontroversial.

The consideration of single-tariff pricing policy can benefit from the perspective provided in Table 10. The relevant sample for considering commission policy with regard to single-tariff pricing is comprised not of all fifty-one public utility commissions (including the District of Columbia). It is more accurate and reasonable to evaluate commission policies with regard to this issue in the context of the twenty-five commissions where multi-system water utilities operate and where the issue has been considered (including the states where single-tariff pricing had been rejected or considered but not approved). Given this context, a clear majority of affected state commissions have allowed regulated water utilities to implement single-tariff pricing (22 state commissions).

Of the remainder, the California commission has allowed partial rate consolidation. For two commissions (Maryland and Mississippi), single-tariff pricing had not been an issue but staff characterized commission policy as "case-by-case." It also is noteworthy that in one of the state's approving a single-tariff pricing structure (Idaho), the matter was "not an issue when proposed." No regulatory commission has steadfastly opposed single-tariff pricing, although many continue to review the merits on case-by-case basis.

TABLE 10
RELEVANT SAMPLE OF STATE PUBLIC UTILITY COMMISSIONS REGARDING THE ISSUE OF SINGLE-TARIFF PRICING POLICY

All state public utility commissions:	**51**
Commissions without jurisdiction for water utilities:	-6
Subtotal	**45**
Commissions without multi-system water utilities:	-15
Subtotal	**30**
Commissions for which single-tariff pricing has never been considered:	-5
Total	**25**

Source: Author's construct. Includes reclassification of Delaware as having a multi-system utility based on a 1999 survey. The total number of commissions includes the District of Columbia.

Pending cases at the time of the original survey in Massachusetts and New Jersey were decided in favor of single-tariff pricing. Soon after, in two significant cases, the Indiana and New Hampshire commissions approved rate consolidation proposals (in 1997 and 1998 respectively). Since the original survey, the Delaware commission approved single-tariff pricing in conjunction with an acquisition that created the state's only multi-system utility (as reflected in Table 10 and elsewhere).

General Findings

The detailed results of the original survey are reported in Appendix E (Tables E1 through E4). The data are reasonably complete for all fifty-one public utility commissions (including the District of Columbia commission). Detailed data on specific utilities are incomplete from a few states because of the difficulty in compiling these data.

As noted in the tables, six public utility commissions do not have jurisdiction for water utilities ("NJ"). In sixteen (16) of the states with jurisdiction for water utilities, staff had observed that no multi-system water utilities were in operation (including Delaware at the time of the original survey). This finding also was established in the *1995 Inventory Report,* which was used to supplement this survey. For the remainder of the survey, responses for these sixteen states were recorded as "NA," or "not applicable."

Thirty (30) state commissions regulate multi-system water utilities, where single-tariff pricing is a potential issue. Of the thirty (30) commissions with multi-system water utilities, twenty-two (22) have approved single-tariff pricing for one or more utilities, including partial consolidation. California regulators have allowed partial consolidation

subject to further deliberations. Seven commissions (7) have not directly addressed this issue. As already noted, these findings have been revised since the original survey to update the findings for five states (Delaware, Indiana, Massachusetts, New Hampshire, and New Jersey) where pending and recent cases have been decided in favor of single-tariff pricing (in Massachusetts, partial consolidation already had occurred).

Of the twelve (12) commissions that had not approved single-tariff pricing at the time of the original survey, three explanations were provided: single-tariff pricing had not been an issue (7 commissions), a proposal for single-tariff pricing was rejected (1 commission), and single-tariff pricing had been considered but not specifically approved (4 commissions). The Indiana commission reportedly rejected single-tariff pricing because of cost-of-service concerns. No commission staff member reported that a statute or policy expressly prohibited single-tariff pricing. However, the Florida survey response indicated that legislation had been proposed to limit the use of rate consolidation to interconnected systems; the legislation was not adopted.

Specific Findings

Data were provided for 213 multi-system utilities, of which 129 had implemented a full version of single-tariff pricing and 20 had implemented partial rate consolidation (that is, single-tariff pricing for all but a few systems or single-tariff pricing for groups of systems within the utility but not for the utility as a whole). Partial rate consolidation in some cases is used to phase-in the single tariff. The survey does not include the multi-system utilities in Texas (estimated at 200 to 300 utilities) or all of the multi-system utilities in Florida (estimated at 60 to 70 utilities) because these data were not readily available. Other states also may have some additional multi-system utilities for which data were not reported. The survey also excludes publicly owned water utilities, with the exception of West Virginia for which data were available for commission-regulated public service districts.

Several states have jurisdiction for only one multi-system water utility. States with more than ten multi-system utilities are Connecticut, Florida, Louisiana, North Carolina, Texas, Washington, and West Virginia. Of these states, only Louisiana has not approved single-tariff pricing.

Based on the available data from the original survey, the number of systems managed by the multi-system utilities ranges from 2 to 201. The average number of systems reported is 11; the median number of systems was 4. The number of connections for the smallest system ranged from 2 to 30,000 with a mean value of 751 and a median value of 30 (based on data for 115 systems). The number of connections for the largest system ranged from 18 to 329,000, with a mean value of 11,615 and median value of 257 (based on data for 115 utilities). The earliest date reported for adopting single-tariff pricing was 1958; the most recent date was 1995 (disregarding the pending or subsequent cases). The average and median time frame for adopting single-tariff pricing was the early 1980s.

At the time of the survey, rate consolidation had been partially implemented for several utilities. In some cases, all but a few systems had been placed under a single tariff; in other cases, the single tariff was being phased-in gradually over time. Only one commission reported that monitoring and evaluation of single-tariff pricing had occurred in the form of reexamining past rate cases (West Virginia).

Characteristics of Single-Tariff Utilities

Single-tariff utilities appear to have some distinguishing features in comparison to multi-system utilities that do not use single-tariff pricing. Data were provided for 213 utilities, of which 129 implemented single-tariff pricing or partial rate consolidation. Data on the approximate number of systems were provided for 203 utilities (149 single-tariff utilities and 54 multi-system utilities without single-tariff pricing). Data on the smallest and largest systems in terms of service connections were available for 115 utilities (81 single-tariff utilities and 34 multi-system utilities without single-tariff pricing). All available data were used to preserve as much information as possible for the analysis. For data reported as a range of values, an average was used (for example, "8 to 9" was replaced with 8.5). For data reported as "<5," a value of 4.5 was used.

The sample is incomplete and nonrandom, so findings based on the available data are not generalizable. Substantial missing data will affect the results of any analysis. However, the data represent a sizable portion of the multi-system utilities regulated by the state commissions. Also, many states reported a mixture of systems with and without single-tariff pricing. Certain observations can be drawn from the data that should lead to further consideration and analysis.

As reported in Table 11 (and Table E2), single-tariff systems and multi-system utilities appear to differ in terms of the number of systems that comprise them, smallest connections, and largest connections. For single-tariff systems, the median number of systems was 5 (average value of 13); for multi-system utilities without single-tariff pricing the median number of systems was 4 (average value of 6). The connection data reveal more striking patterns. Along every measurement (except for the minimum of 2 connections for the smallest systems for both utility types), single-tariff utilities appear to be much smaller in terms of both smallest and largest systems based on connections.

This finding is very consistent with the perception that single-tariff pricing is most needed, and perhaps most justified, when numerous very small water systems are involved. These data may indicate that commission approval of single-tariff pricing takes into account these basic descriptive characteristics. This is not to suggest, however, that single-tariff pricing only has been (or should be) approved for utilities made up of very small systems. In fact, some of the more recent decisions affirming single-tariff pricing have involved utilities with systems that are fairly substantial in size.

Table 11
Comparative Analysis of Multi-System Utilities With and Without Single-Tariff Pricing

Utilities	Number of Utilities Reported		Approximate Number of Systems				Smallest System (N Connections)				Largest System (N Connections)			
	Approx. Systems	Connec-tions	Mini-mum	Maxi-mum	Aver-age	Median	Mini-mum	Maxi-mum	Aver-age	Median	Mini-mum	Maxi-mum	Aver-age	Median
All Multi-System Utilities	203	115	2	201	11	4	2	30,000	751	30	18	329,000	11,615	257
Multi-System Utilities With Single-Tariff Pricing	149	81	2	201	13	5	2	2,400	122	20	18	97,000	5,651	193
Multi-System Utilities Without Single-Tariff Pricing	54	34	2	32	6	4	2	30,000	2,251	82	26	329,000	25,824	1,254

Source: Table E1. Not adjusted for cases pending at the time of the survey or subsequent cases in which consolidated rates were approved for individual utilities in Delaware, Indiana, Massachusetts, New Hampshire, and New Jersey.

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Arguments in Favor of Single-Tariff Pricing

In the course of the survey, regulatory commission staff members were asked to consider key arguments for and against the adoption of single-tariff pricing. Various reasons for commission approval of rate consolidation were provided in the survey. Table E1 provides the primary reasons for approval. Cost savings were frequently mentioned. As reported in Table E3, commission staff members also were asked to identify the arguments that influenced their commissions' deliberations or policies regarding rate consolidation.

These data reflect only staff member views, not necessarily the views or policies of the commissions. Twenty-one (21) commission staff members responded to this portion of the survey. The data exclude thirty commissions where, at the time of the survey, single-tariff pricing had not been an issue and staff views were not elicited. [60] Staff could cite more than one argument and no weighting or ranking of arguments was required. In decreasing order of mentions (indicated in parentheses), commission staff indicated agreement with the following arguments in favor of single-tariff pricing:

- Mitigates rate shock to utility customers (17)
- Lowers administrative costs to the utilities (16)
- Provides incentives for utility regionalization and consolidation (15)
- Physical interconnection is not considered a prerequisite (13)
- Addresses small-system viability issues (13)
- Improves service affordability for customers (12)
- Provides ratemaking treatment similar to that for other utilities (10)
- Facilitates compliance with drinking water standards (9)
- Overall benefits outweigh overall costs (9)
- Promotes universal service for utility customers (8)
- Lowers administrative cost to the commission (8)
- Promotes ratepayer equity on a regional basis (6)
- Encourages investment in the water supply infrastructure (5)
- Promotes regional economic development (3)
- Encourages further private involvement in the water sector (2)
- Other: Can be consistent with cost-of-service principles (1) and found to be in the public interest (1)

Staff members also noted that single-tariff pricing could be consistent with cost-of-service principles (New York), that separating small-system costs may not always be cost-effective (Virginia), and that the genesis for the issue was regulatory simplification (California). Mitigating rate shock also was equated with "rate stability" (Indiana). Vermont regulators found that single-tariff pricing addressed small system viability issues and generally was in the public interest, approving the method over the objections of staff

[60] Excluded were 6 commissions without jurisdiction for water utilities, 16 commissions without jurisdiction for multi-system water utilities ("not applicable"), and 8 commissions that regulate multi-system utilities but where single-tariff pricing has not been an issue (including the Idaho commission, where single-tariff pricing was approved for one utility but not an issue of significance).

members concerned about subsidization issues. Typically, more than one argument affects commission deliberations regarding rate consolidation.

Arguments Against Single-Tariff Pricing

Commission staff members also evaluated the key arguments against rate consolidation. Various reasons for commission disapproval of single-tariff pricing were provided. Table E1 provides the primary reason for the disapproval. Cost-of-service issues were frequently mentioned, although some staff also indicated that single-tariff pricing could be consistent with cost-of-service principles. As reported in Table E4, commission staff members also were asked to identify the arguments that influenced their commissions' deliberations or policies regarding rate consolidation.

These data reflect only staff member views, not necessarily the views or policies of the commissions. As mentioned earlier, twenty-one (21) commission staff members responded to this portion of the survey based on their experience with the issue of single-tariff pricing for multi-system utilities. Staff could cite more than one argument and no weighting or ranking of arguments was required. In decreasing order of mentions (indicated in parentheses), commission staff indicated agreement with the following arguments against single-tariff pricing:

- Conflicts with cost-of-service principles (14)
- Provides subsidies to high-cost customers (12)
- Not acceptable to all affected customers (10)
- Considered inappropriate without physical interconnection (8)
- Distorts price signals to customers (7)
- Fails to account for variations in customer contributions (6)
- Justification has not been adequate in a specific case (or cases) (6)
- Discourages efficient water use and conservation (4)
- Encourages growth and development in high-cost areas (4)
- Undermines economic efficiency (3)
- Provides unnecessary incentives to utilities (2)
- Not acceptable to other agencies or governments (2)
- Insufficient statutory or regulatory basis or precedents (2)
- Overall costs outweigh overall benefits (2)
- Encourages overinvestment in infrastructure (1)

Regarding unacceptability to other agencies or governments, the California staff member noted that opposition to single-tariff pricing had come from other utilities.

9. Commission Policies on Rate Consolidation

As already noted, twenty-two (22) state commissions have allowed regulated water utilities to implement single-tariff pricing. Single-tariff pricing is generally accepted in eight (8) states, as summarized in Table 12 and Figure 10 (and detailed in Table E1). Texas commission staff members noted that single-tariff pricing was accepted "and preferred." In fact, the Texas commission provides a simplified procedure for merging the rates of acquired systems with the rates of the acquiring utility. While the regulated water utility usually requests consolidated rates, at least one commission (New York) has imposed its use. Pennsylvania staff noted that the use of single-tariff pricing has evolved from its application on the basis of physical interconnection to its application on the basis of common ownership.

Based on the updated survey findings, staff members at seventeen (17) commissions characterized the policies of their commissions as "case-by-case," indicating that the use of single-tariff pricing must be justified for every specific application (even when the policy is "generally accepted"). In many states, only some of the multi-system utilities under commission jurisdiction are implementing single-tariff pricing. In fourteen (14) of the case-by-case commissions, single-tariff pricing has been approved (including the five recent cases decided in favor of single-tariff pricing). In California, regulators have approved partial rate consolidation. In the two (2) other case-by-case commissions, single-tariff pricing has not been approved or considered in the context of a regulatory proceeding.

Commission Decisions

The experience of West Virginia-American Water Company stands as one of the least controversial and most enduring examples of single-tariff pricing. Implementation of single-tariff pricing has played a role in the company's expansion. A case study of the West Virginia experience appeared in a 1984 issue of the *American Water Works Association Journal*.[61]

In its order, the West Virginia Public Service Commission considered the consistency of single-tariff pricing with the commission's general regulatory obligations and operating principles, finding that:

1. The company's single tariff pricing proposal resulted in a just, reasonable, sufficient and nondiscriminatory rate for all the customers of the company.
2. Each customer will pay the same rate for a like and contemporaneous service made under the same or substantially similar circumstances and conditions.

[61] Limbach (1984).

Table 12
Summary of State Public Utility Commission Policies on Single-Tariff Pricing for Water Utilities

Commission Policy	State Commissions	
Generally Accepted (8)	Connecticut	Pennsylvania
	Missouri	South Carolina
	North Carolina	Texas
	Oregon	Washington
Case-By-Case (17)	Single-Tariff Pricing Has Been Approved (14)	
	Arizona	New Hampshire (d) (f)
	Delaware (a)	New York
	Florida	New Jersey (e) (f)
	Idaho (not an issue)	Ohio
	Illinois	Vermont
	Indiana (b) (f)	Virginia
	Massachusetts (c) (f)	West Virginia
	Single-Tariff Pricing Has Not Been Approved (3)	
	California (g)	
	Maryland (not an issue)	
	Mississippi (not an issue)	
Never Considered (5)	Iowa	Maine
	Kentucky	Wisconsin
	Louisiana	
Not Applicable – No Multi-System Water Utilities (15)	Alabama	Nevada
	Alaska	New Mexico
	Arkansas	Oklahoma
	Colorado	Rhode Island
	Hawaii	Tennessee
	Kansas	Utah
	Montana	Wyoming
	Nebraska	
No Jurisdiction for Water Utilities (6)	Georgia	North Dakota
	Michigan	South Dakota
	Minnesota	Washington, D.C.

Source: Author's construct based on survey of state public utility commission staff members, January-February 1996 and subsequent contacts with the commissions (including a follow-up survey in early 1999).

(a) Reclassified from "not applicable" following an acquisition with approval of consolidated rates.
(b) Since the original survey, a case was decided in favor of single-tariff pricing (previously rejected).
(c) A pending case at the time of the original survey was decided in favor (partial consolidation previously).
(d) Since the original survey, a case was decided in favor of single-tariff pricing.
(e) A pending case at the time of the original survey was decided in favor.
(f) Characterization of commission policy as "case-by-case" was unchanged following the recent decisions.
(g) Partial consolidation with possible phase-in of single-tariff pricing. A case was pending in 1999.

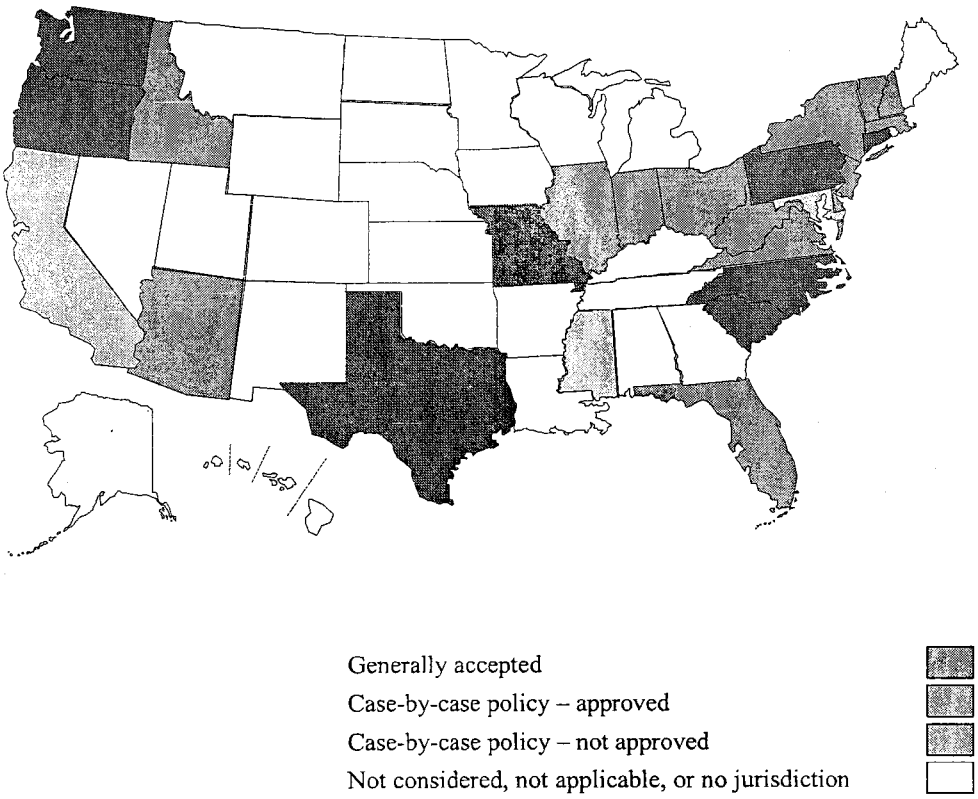

Figure 10. Summary of Commission Policies on Rate Consolidation.

3. The approval of the company's proposal was in compliance with the commission's duty to regulate utilities of this state in order to provide the availability of adequate, economical, and reliable utility services to encourage the well planned development of the utility resources in a manner consistent with the state needs and in a way consistent with the productive use of the state's energy resources.
4. Single tariff pricing strikes a reasonable balance in the interest of current and future water consumers, the general interest of the state's economy, and the interest of West Virginia Water Company.[62]

[62] Order of the West Virginia Public Service Commission as cited in Limbach (1984), 55.

In a 1986 order, the Pennsylvania Public Utility Commission approved single-tariff pricing for Western Pennsylvania Water Company (1986) and provided several pragmatic reasons for approving this pricing strategy.[63] First, a larger rate and revenue base ameliorates the impact of major capital additions needed from time to time in every service area. Second, a larger revenue base promotes flexibility in timing and financing major capital additions. Third, the impact of instability resulting from changes in sales volumes is mitigated when the effect of such volumetric factors is spread over a larger economic base. Finally, the reduction of the number of accounting units and the number of individual rate filings result in administrative efficiency with a potential to reduce costs to ratepayers.

Ten years later, in a general proceeding on acquisition policy, the Pennsylvania Commission stated its belief "that every system and every ratepayer in the Commonwealth will eventually be in need of specific service improvements and at that point, the true benefits of single tariff pricing will be realized by all citizens in the Commonwealth."[64] The Commission now views single-tariff pricing as a central component of acquisition incentives provided to jurisdictional utilities.

Although single-tariff pricing has been approved without much consternation in some jurisdictions, in others the level of controversy has been much more pronounced. Consumer advocates, local governments, large-volume users, and commission staff members (even within agencies) have at times been deeply divided on this issue.

The regulatory commissions have struggled in particular with whether or not *physical interconnection* among water systems should be a prerequisite for single-tariff pricing.[65] As noted by the Massachusetts Department of Public Utilities, physical interconnection is not necessarily required: "[S]everal factors (viz., the contiguity of the communities served in that zone; the commonality of personnel for meter-reading, operations, maintenance, and construction duties; and administrative convenience) are decisive in favor of treating the [two communities] as a single zone . . ."[66]

Similarly, the Florida Public Service Commission once concluded that state law supports the view that multi-system utilities can be considered a single system because the utility's facilities and land are *functionally related* (in administrative, operational, and managerial terms); even without physical interconnection.[67] An analogy provided in the case was that the multi-system utility operations were like a "wagon wheel," where the separate service territories are the spokes and utility management is the rim holding them together.

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[63] Pennsylvania Public Utility Commission, Order in Docket R-850096, Western Pennsylvania Water Company (1986), 148.

[64] Pennsylvania Public Utility Commission, Order in Docket M-00950686, Policy Statement Re: Incentives for the Acquisition and Merger of Small, Nonviable Water and Waste Water Systems (1996).

[65] Physical interconnection in the other industries may be the reason why pricing across larger regions tends to prevail.

[66] Massachusetts Department of Public Utilities, Order in Docket No. 90-146, Massachusetts-American Water Company (1990), 3-4. See also MA DPU 95-118 (1996).

[67] Florida Public Service Commission, Order No. PSC-96-1320-FOF-WS, Docket No. 950495-WS, Southern States Utilities (1996).

Following an appeal of the Florida order, however, the District Court held that rate consolidation need not be conditioned on a finding by the commission that the systems involved are functionally related. "Because we decide that the determination of functional relatedness is not controlling on the issue of whether uniform rates can be set," noted the Court, "we express no opinion on whether the utility systems involved in this rate case were 'functionally related.'"[68]

In a 1993 case, the Illinois-American Water Company articulated the variety of ways in which the systems of a multi-system utility are *operationally related:*

> All operation and maintenance and construction activities are performed on a uniform basis throughout the five districts. . . All five districts utilize similar facilities, such as pumping stations and purification plants, transmission and distribution mains, storage reservoirs, service lines and meters. . . All five districts utilize the same engineering and construction standards, maintenance programs, operating procedures, inspection programs, budgeting and accounting procedures, types of materials and supplies and management structure. . . All five districts utilize the services of the American Water Works Service Company (the "Service Company"), which provides, pursuant to a contract with the Company, support to Illinois-American personnel in the areas of accounting, engineering operations, rate design, regulatory practices, finance, water quality, information systems, personnel information and training, purchasing, insurance, safety and community relations.[69]

The company also argued that the evolving *corporate* structure of the multi-system utility is germane to these issues, as described in Illinois Commerce Commission's order:

> According to Illinois-American, another important factor supporting the adoption of single tariff pricing are the many steps the Company has taken in recent years to centralize and consolidate its operations. . . Illinois-American, as it presently exists, is the result of two mergers. Pursuant to the mergers, which were approved by the Commission. . . water systems once operated as five separate companies were merged to form a single integrated unit, rather than as five independent, stand-alone systems.[70]

Staff members of the Illinois Commerce Commission found that "Commission practices in Illinois. . . support the uniform rate concept."[71] In this particular proceeding, the commission approved partial rate consolidation and ordered Illinois-American to submit a proposal for company-wide single-tariff pricing.

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[68] District Court of Appeal, First District, State of Florida, Decision in Case No. 96-447 (June 10, 1998), 1.
[69] Illinois Commerce Commission, Order Docket No. 92-0116, Illinois-American Water Company (1993).
[70] Ibid., 85.
[71] Ibid., 87.

In a parallel proceeding, Indiana-American Water Company argued before the Indiana Utility Regulatory Commission that single-tariff pricing is justified in part on the grounds that the company's districts are managed by a single corporate structure and financed through a common capital structure.[72] The Indiana Office of Consumer Counselor opposed this reasoning and the Indiana Commission rejected that particular bid for single-tariff pricing, but the company prevailed in a 1997 proceeding (discussed below).

Another rationale in the regulatory context is that rate consolidation can help reduce the frequency and complexity of rate filings by regulated firms. According to John Guastella, regulatory acceptance of single-tariff pricing as a matter of policy reduces costs associated with preparing separate cost-of-service studies to allocate common costs among the separate systems, and thus significantly reduces the cost of utility rate filings.[73] A related point is that rates under a single tariff are easier to communicate to customers (lowering administrative costs) and easier for customers to understand.

In some deliberations, the focus is shifted from differences in the *cost of service* to comparability in the *value of service* that utility customers receive regardless of their spatial location. Indiana-American Water Company has argued that, "The single tariff pricing concept is supported by the fact that any one of the Company's customers, regardless of where that customer is located, expects, is entitled to and receives essentially the same service as the customers in any other district."[74]

In a recent regulatory proceeding involving the New Jersey-American Water Company, the administrative law judge echoed this argument:

> Inasmuch as all customers of New Jersey-American, be they New Jersey Commonwealth or Monmouth customers, receive comparable service on a comparable basis, it seems only appropriate that all customers be charged similarly. . . By distributing the burden of system improvement to all customers, the relative impact is decreased. All Company customers in the three operating groups are benefiting by the relative economics [sic] of scale and system integration and administration the unified company produces. Likewise, all customers should equally shoulder the costs involved.[75]

The New Jersey Board of Public Utilities agreed with the administrative law judge in adopting a statewide (single-tariff) price for the New Jersey-American Water Company in this particular proceeding.

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[72] Richard E. Hargraves, Direct testimony in Cause No. 39595 before the Indiana Utility Regulatory Commission, Indiana-American Water Co., Inc. (1993).
[73] Guastella (1994).
[74] Hargraves (1993).
[75] New Jersey Board of Public Utilities, OAL Docket No. PUC 520795, Agency Docket No. WR-95040165, New Jersey-American Water Company (1996), 14-15.

Several of the commissions have implemented variations of single-tariff pricing or partial forms of rate consolidation. The Missouri Public Service Commission, for example, once reasoned that rate shock is the result of rate *changes* not rate *levels*. Thus the commission ordered the company in question to maintain existing rate differentials while equalizing future rate increases. By maintaining current rate differentials and equalizing rate increases, rate shock is minimized, subsidization is limited, and the company is afforded greater flexibility in timing plant additions.[76] The commission later found, for another company, that the movement toward rate consolidation was in the public interest.[77] But in a subsequent rate case, and to the understandable chagrin of the utility, the commission reiterated "that it is not committed to a specific position regarding cost recovery for capital plant additions by means of [single-tariff pricing]."[78]

In a phased approach, implementation of single-tariff pricing may occur over several commission decisions involving the same multi-system utility. According to a former regulator, a phase-in plan may be especially justified when differences in rates are "extreme."[79] A phased approach "facilitates the goal of single tariff pricing, but does not negate the requirement for future commission approval of its full implementation."[80]

Interestingly, zonal rates for *groups* of systems can be used in conjunction with a phased approach to rate consolidation. The Florida commission recently advanced a "capband" approach establishing rates for groups of systems with similar cost characteristics, reasoning that:

> First, the capband structure represents a greater move toward the long term goal of a uniform rate. It eliminates the need for separate rate structures for each individual service area under the cap. The number of rates would decrease from 56 to eight for the water facilities under the cap, and from 23 to six for the wastewater facilities. Second, as noted above, the capband structure reduces subsidies in terms of deviation from stand-alone rates. This is true both in terms of number of service areas and number of customers. Uniform rates within the band mitigate the subsidy within the band. . . [The capband rate structure] embraces all of the advantages of the modified stand-alone rate structure and adds the additional advantages of simplifying the rate structure by moving the utility closer to a uniform rate.[81]

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[76] Missouri Public Service Commission, Order in Case No. 90-236, Missouri Cities Water Co. (1990).
[77] Missouri Public Service Commission, Order in Case Nos. WR-95-205 and SR-95-206, Missouri-American Water Company (1995).
[78] Missouri Public Service Commission, Order in Case Nos. WR-97-237 and SR-97-238, Missouri-American Water Company (1997).
[79] Wendell F. Holland, "Acquisition Incentives Encouraging Regionalization in the Water Industry" a speech made at the Great Lakes Conferences of the National Association of Regulatory Utility Commissioners in Greenbrier, West Virginia (July 11, 1995).
[80] Pennsylvania Public Utility Commission, Western Pennsylvania Water Company, 72 PUR 4th (1986), 154.
[81] Florida Public Service Commission, Order No. PSC-96-0549-PHO-WS, Docket No. 950495-WS, Southern States Utilities (1996), 78-79.

The Florida decision was appealed on a variety of grounds. As noted earlier, the Court of Appeal held that the commission need not determine that utility facilities are "functionally related" prior to approving consolidated rates. In the same decision, the Court also found that "no statute prohibits resort by the Public Service Commission (PSC)—in an appropriate case—to so-called "capbands" to fix rates that are just, reasonable, compensatory, and not unfairly discriminatory."[82] Specifically:

> Nothing inherent in the capband methodology runs afoul of the statute. The order under review sets rates [footnote omitted] so that no ratepayer's rates exceed by more than seven per cent what they would have been if each system's rates had been set on a stand alone, cost of service basis. This modest deviation from a pure cost of service basis for individual rates pales by comparison to the magnitude of inevitable intra-system subsidization. Nor is a pure cost of service basis as to each individual ratepayer mandated by a statute which directs that "the commission shall consider the value and quality of service and the cost of providing service." § 367.081(2), Fla. Stat. (1997). See *Occidental Chem. Co. v. Mayo*, 351 So. 2d 336, 340 (Fla. 1977) ("Given the multiplicity of methods suggested by the experts to allocate expenses between various users, we cannot say that the Commission departed from the essential requirements of law in relying on a range of criteria for this purpose."). A shift in the direction of "affordability" takes the value of service into account. Although using stepped rates or "capbands" requires offsetting increases and does not spread offsets perfectly evenly among households paying less than maximum rates, such use need not lead to unfairly discriminatory rates.[83]

The Indiana Utility Regulatory Commission articulated the pragmatic rationale for single-tariff pricing in the recent Indiana-American case.[84] The press release accompanying the commission's order asserts that the company's movement toward single-tariff pricing is "in the best interest of all of the customers" and that all areas will benefit in the long term by increased rate stability and mitigation of construction cost impacts. The order found that single-tariff pricing was consistent with pricing for other utility and nonutility services and that it would help the company meet demands associated with environmental compliance, infrastructure replacement, and service adequacy for customers.[85] The commission also addressed the issue of price discrimination:

> There will always be customers who over a given period of time will be required to pay higher rates than would result if they were included in some smaller or different customer group. But this does not mean undue discrimination exists so long as they are paying an equivalent price for an equivalent product. Moreover, we must not forget that all of the customers today are the beneficiaries of water facilities

[82] District Court of Appeal, First District, State of Florida, Decision in Case No. 96-447 (June 10, 1998), 1.
[83] Ibid., 13.
[84] Indiana Utility Regulatory Commission, Order in Cause No. 40703, Indiana-American Water Company (1997).
[85] Ibid., 77.

> built in the past, and the cost of developing these facilities was borne in large part by earlier generations of customers.[86]

As a general rule, individual water utilities must make the case for single-tariff pricing before regulators, who consider the merits on a case-by-base basis. The Indiana-American decision also is instructive on this point because the case was made by the utility several times—and the arguments rejected—before regulators were persuaded that single-tariff pricing was in the public interest. As with many initiatives by utilities, regulatory approval often requires more than one attempt, as well as modifications to the proposed method to address the legitimate concerns of regulators and consumer advocates.

A few commissions have explicitly recognized single-tariff pricing as a policy tool. As already noted, Pennsylvania regulators have placed single-tariff in the broader context of regulatory policies to promote regionalization and specifically the acquisition of smaller, nonviable systems.[87] The general provisions of the commission's policy, appearing in Table 13, provides for the application of single-tariff pricing to the rates of acquired water systems "to the extent that is reasonable."[88]

Similarly, New York Public Service Commission staff members expect acquiring utilities to include a plan for "rate equalization" (with phase-in provisions as appropriate) as part of petitions for acquisition incentive mechanisms. [89]

Connecticut regulators have interpreted state statutes to authorize rate equalization in connection with mandated takeovers.[90] The commission also recognizes the potential use of annual price caps (to avoid rate shock) and surcharges ("so that customers of the acquiring company are not always obligated to assume full responsibility for the cost of ordered improvements to the acquired company").[91]

Implementation Strategies

Utility regulators can consider several implementation strategies if they find that rate consolidation is in the public interest. Implementing the single tariff can be accomplished in conjunction with acquisition proceedings. Utilities can phase-in single-tariff pricing for all or part of their service territory. A partial form of single-tariff pricing is to adopt a

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[86] Indiana Utility Regulatory Commission, Order in Cause No. 40703, Indiana-American Water Company (1997), 81.
[87] Holland (1995), 10.
[88] Pennsylvania Public Utility Commission, Order in Docket M-00950686, Policy Statement Re: Incentives for the Acquisition and Merger of Small, Nonviable Water and Waste Water Systems (1996).
[89] New York Public Service Commission, Order in Case 93-W-0962, Investigation of Incentives for the Acquisition and Merger of Small Water Utilities (1993), Appendix E.
[90] Connecticut General Statutes, 16-262o. According to Connecticut Statutes (16-262r), rate equalization also can be used in connection with satellite management of a smaller by a larger system.
[91] Connecticut Department of Public Utility Control, Order in Docket No. 96-03-31, DPUC Review of Water Companies Acquisitions and Transfer Processes (January 8, 1997), 27.

common fixed or customer charge for all utility customers, and alter variable charges based on variations in the cost of service. Utilities can use surcharges or other mechanisms to differentiate prices based on extraordinary costs and send customers a very specific price signal. A partial approach to single-tariff pricing is to develop tariffs based on groupings of systems or "zones" with roughly similar cost or service characteristics. Another partial approach, mentioned earlier, is to use a phased method of implementation by which rates are made more uniform over several rate adjustments.

Innovative pricing options and implementation strategies for water utilities can emerge in the context of regulatory proceedings, dispute resolution processes, and a continuing dialog among utilities, consumers, consumer advocates, and other interested stakeholders.

Related Strategies

Commissions may want to consider implementing specific regulatory strategies in conjunction with single-tariff pricing. First, regulators could use auditing or other evaluation techniques to establish that utilities are meeting efficiency and other performance goals. Second, the commission could coordinate with other regulatory agencies to promote compliance with water quality standards. Third, regulators could evaluate the long-term strategic plans of water utilities for serving customers throughout their service territories. Fourth, features of the consolidated rate could be assessed in terms of their effectiveness in promoting efficient water use and discouraging waste. Fifth, the commissions could implement a monitoring and evaluation system to assess the effects of consolidated rates on all systems and customer groups. Sixth, alternative dispute resolution could be encouraged to provide parties with a forum for participation and an opportunity to reach a settlement agreement on single-tariff pricing issues. Finally, regulators could assess utility efforts to communicate with customers about the value of water and build understanding of the rate structure.

Commission Authority

Commission authority to approve consolidated rates has been met with legal challenges in some jurisdictions. Obviously, single-tariff pricing policy must be consistent with a state's legislative framework and legally sustainable. Regulatory and legal doctrine generally seem to permit this pricing method. Legislative, judicial, or other constraints on rate consolidation would be undesirable from a public policy standpoint and undermine the ability of the regulatory commissions to craft effective policies for the water industry.

In a recent case, the New Hampshire Public Utilities Commission acknowledged the absence of a clear regulatory standard for, or prohibition of, the use of single-tariff pricing. The commission essentially asserted its policymaking authority to approve rate consolidation based on a public-interest standard:

> While New Hampshire law is replete with references to the appropriate standard for establishing a utility's rate base and rate of return, there appears to be no specific guidance on the point of rate consolidation or single tariff pricing. Thus, in the absence of any legal impediment to utilizing single tariff pricing, our decision essentially becomes one of policy that is bound only by our statutory constraints that rates be just and reasonable and that we act in the public interest. See RSAs 374:2 and 378:28.
>
> Opponents of rate consolidation in this case argue that we should adhere to our traditional ratemaking policy of cost causation. We find their position unpersuasive in this case for two reasons. First, traditional cost of service regulation already includes some measure of rate averaging in that customers are not charged the true costs of serving them on an individual basis. Second, and perhaps more important, stand alone rates in this case produce results for some customers that are well beyond the zone of "just and reasonable." One needs only to look at the stand alone rates that would result from the settlement Agreement to see just how extreme the results are when significant investments are required in a very small system. Most of the community systems are simply too small to absorb the magnitude of investments mandated by environmental enactments. However, without these investments, it is clear that the small community systems would have been unable to provide safe and adequate water service to their customers.[92]

Single-tariff pricing evolved as a legitimate policy tool and is used by a clear majority of the states that regulate multi-system water utilities. Rate consolidation is a tool that can be used on a case-by-case basis, where regulators carefully weigh the evidence before them, and as a general policy tool to encourage acquisitions and regionalization. The precarious condition of very small water systems merits the consideration of alternative regulatory approaches, including consolidated rates.

Rate consolidation will continue to focus attention on some fundamental regulatory issues: Does it result in a measurable "subsidy"? Does the subsidy constitute a form of price discrimination? Are the resultant rates just and reasonable? Do the long-term benefits of implementing single-tariff pricing, including subsidization, outweigh the costs? Regulators must be satisfied with the answers to these questions before approving a rate consolidation strategy. Generally, however, the commissions are arriving at conclusions that support the use of single-tariff pricing.

The commissions have demonstrated their policymaking authority to approve consolidated rates, as well as their capacity to consider and weigh the complex ratemaking and policy tradeoffs involved. Only the commissions can specify the circumstances appropriate for single-tariff pricing in their jurisdictions. Water utilities should continue to advance innovative pricing strategies. The commissions should continue to exercise due diligence in approving water rate structures that serve the public interest.

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[92] New Hampshire Public Utilities Commission, Order in Docket DR 97-058, Pennichuck Water Works, Inc. (1998).

Table 13
Pennsylvania Public Utility Commission
Policy Statement on Acquisition Incentives

Title 52, Part I, Chapter 69

Incentives for Acquisition and Merger of Small Nonviable Water Utilities--
Statement of Policy

§ 69.711. ACQUISITION INCENTIVES

(a) General

To accomplish the goal of increasing the number of mergers and acquisitions to foster regionalization, the Commission will consider the acquisition incentives at subsection (b). However, the following parameters must first be met in order for Commission consideration of a utility's proposed acquisition incentive. It should be demonstrated that:

(1) The acquisition services the general public interest;

(2) The acquiring utility meets the criteria of viability which will not be impaired by the acquisition; that it maintains the managerial, technical, financial capabilities to safely and adequately operate the acquired system, in compliance with the Public Utility Code, the Sate Drinking Water Act, and other requisite regulatory requirements on a short and long term basis;

(3) The acquired system has less than 3300 customer connections; the acquired system is not viable; it is in violation of statutory or regulatory standards concerning the safety, adequacy, efficiency or reasonableness of service and facilities; and that it has failed to comply within a reasonable period of time, with any order of the Department of Environmental Protection or the Public Utility Commission;

(4) The acquired system's ratepayers should be provided with improved service in the future, with the necessary plant improvements being completed within a reasonable period of time;

(5) The purchase price of the acquisition is fair and reasonable and the acquisition has been conducted through arm's length negotiations; and

(6) The concept of single tariff pricing should be applied to the rates of the acquired system, to the extent that is reasonable. Under certain circumstances of extreme differences in rates, and/or affordability concerns, consideration should be given to a phase-in of the rate difference over a reasonable period of time.

Table 13 (continued)

(b) Acquisition Incentives

In its efforts to foster acquisitions of suitable water and sewer systems by viable utilities when such acquisitions are in the public interest, the Commission seeks to assist these acquisitions by permitting the use of a number of regulatory incentives. Accordingly, the Commission will consider the following acquisition incentives:

(1) Rate of Return Premiums - Additional rate of return basis points may be awarded for certain acquisitions and for certain associated improvement costs, based on sufficient supporting data submitted by the utility within its rate case filing;

(2) Acquisition Adjustment - In cases where the acquisition costs are greater than the depreciated original cost, that reasonable excess may be included in the rate base of the acquiring utility and amortized as an expense over a 10-year period;

(3) Deferral of Acquisition Improvement Costs - In cases where the plan improvements are of too great a magnitude to be absorbed by ratepayers at one time, rate recovery of the improvement costs may be recovered in phases. There may be a one time treatment (in the initial rate case) of the improvement costs but a phasing-in of the acquisition, improvements and associated carrying-costs may be allowed over a finite period; or.

(4) Plant Improvement Surcharge - Collection of a different rate from each customer of the acquired system upon completion of the acquisition could be implemented to temporarily offset extraordinary improvement costs. In cases where the improvement benefits only those customers who are newly acquired, the added costs may be allocated on a greater than average level (but less than 100%) to the new customers for a reasonable period of time, as determined by the Commission.

(c) Procedural Implementation

The appropriate implementation procedure for the acquisition incentives listed would be to file the request during the next filed rate case. In the case of the first incentive, for example, the rate of return premium, appropriate supporting data should be filed within the rate of return section in order for Commission evaluation of its applicability. The rate of return premium as an acquisition incentive may be the most straightforward and its use is encouraged.

Other appropriate incentives may be considered by this Commission, provided they meet the parameters listed at subsection (a). Acquisition incentive requests will be considered on a case by case basis. In acquisition incentive filings, the burden of proof rests with the acquiring utility.

Source: Pennsylvania Public Utilities Commission, Incentives for Acquisition and Merger of Small Nonviable Water Utilities: Statement of Policy (February 28, 1996).

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APPENDIX A
GLOSSARY OF TERMS

Block rate. A billing rate applied to water usage that varies according to blocks of water usage (measured in gallons or cubic feet). See *uniform rate, decreasing-block rate,* and *increasing block rate.*

Common-management costs. Costs that are incurred on the basis of the joint operation of multiple systems. Costs under common management, given management economies of scale and scope, should be less for the utility than the sum of **stand-alone** costs for all of the operated systems.

Decreasing-block rate. A *variable rate* that decreases with additional blocks of water usage. See *uniform rate and increasing-block rate.*

Equity. A condition under which costs have been fairly allocated among customer groups consistent with cost-of-service and *efficiency* criteria. See *horizontal equity, vertical equity,* and *subsidy.*

Efficiency. A condition under which prices charged, and quantities produced and used, are optimal (that is, not too low or too high).

Fixed charge. The portion of a customer's water bill that does not vary with water usage. Fixed charges often are used to recover administrative and other recurring costs that are not determined by water usage. The fixed charge may include a minimal water allowance, above which a *variable rate* is applied.

Horizontal equity. A condition under which customers that impose similar costs on the utility system pay similar prices for comparable utility services. See *vertical equity.*

Intergenerational equity. A condition under which one generation of customers does not pay for costs imposed on the utility system by another group of customers. See *horizontal equity* and *vertical equity.*

Increasing-block rate. A *variable rate* that increases with additional blocks of water usage. See *uniform rate* and *decreasing-block rate.*

Investor-owned (or privately owned) utility. A utility owned and operated by a private firm on a for-profit basis. See *publicly owned utility.*

Just and reasonable. A concept used to evaluate utility rates related to the concept of **undue discrimination.**

Multisystem utilities. Public or private utilities that operate two or more water systems serving distinct service territories; systems may or may not be physically interconnected.

Municipal-unit doctrine. The treatment of a municipality as a distinct service territory and unit for cost allocation and ratemaking purposes (that is, "city-based" rates).

Phase-in (rates). Implementation of a significant change in rate levels or rate design in phases, rather than at once, in order to reduce rate shock to customers and revenue instability to the utility. Reflects the principle of gradualism.

Physically interconnected systems. Water systems joined by a system of pipes and pumps for transporting water (usually treated water) from one system to another.

Primacy agency. A state agency responsible for regulating community and noncommunity water systems to ensure compliance with federal drinking-water standards established under the Safe Drinking Water Act.

Privately owned (or investor-owned) utility. A utility owned and operated by a private firm on a for-profit basis. See *publicly owned utility.*

Public Utility Commission (PUC). A state agency responsible for regulating the rates and profits of public utility monopolies.

Publicly owned utility. A utility owned and operated by a governmental agency, such as a municipality, on a nonprofit basis. See *privately owned utility.*

Safe Drinking Water Act (SDWA). The federal statute that establishes drinking-water standards for community and noncommunity water systems. Substantial amendments to the SDWA were enacted in 1986 and 1996.

Service territory. The geographic area served by a public utility; a utility's service territory may or may not correspond to geopolitical boundaries.

Single-tariff pricing. Single-tariff pricing is the use of a unified rate structure for multiple water (or other) utility systems that are owned and operated by a single utility, but that may or may not be physically interconnected. Under single-tariff pricing, all customers of the utility pay the same rate for service, even though the individual systems providing service may vary in terms of operating characteristics and stand-alone costs.

Stand-alone pricing. Pricing based on the costs that a commonly owned or managed water system would incur if it replicated the same services and functions on a basis completely independent of the parent utility and other systems.

Subsidy. A transfer of welfare from one group of customers to another that is not based on differences in the cost of serving the different customer groups.

Tariff. The official rate schedule document specifying all of a utility's rates and charge; the tariff must be approved by appropriate state or local governing bodies.

Undue discrimination. Price differentiation that is not based on variations in the cost of service.

Uniform rate. A *variable* rate that does not change with the total amount of water usage.

Variable rate. The billing rate applied on a per gallon or per cubic foot basis to the amount of water used by customers

during the billing period. The variable rate multiplied by water usage determines the portion of a customer's water bill that varies with water usage.

Vertical equity. A condition under which customers that impose different costs on the utility system pay different prices for utility services based on the relevant cost differences. A related concept is **undue discrimination.**

Water system. An infrastructure system for withdrawing, transporting, treating, storing, and distributing water to a defined service territory.

Water utility. A public or private entity that owns and operates one or more *water systems* and typically charges customers for the cost of providing water service. In *multi-system* utilities, two or more water systems are owned and operated by the utility and they may or may not be *physically interconnected.*

Zonal Pricing. Differentiation in rates according to substantial differences in the cost of serving different areas. Zones generally are defined in spatial terms and represent geographic clusters of customers with similar cost characteristics.

APPENDIX B
SELECT COMMISSION ORDERS ON SINGLE-TARIFF PRICING

California

California Public Utilities Commission. Decision No. 89-06-007. Hillview Water Company, Inc. June 7, 1989.

Connecticut

Connecticut Department of Public Utility Control. Docket No. 86-12-08. Connecticut-American Water Company. June 2, 1987

_____. Docket No. 89-03-22. Connecticut-American Water Company. September 21, 1987.

Florida

Florida Public Service Commission. In re Rate Setting Procedure and Alternatives for Water and Sewer Utilities. 1989.

_____. Docket No. 920100-WS. Southern States Utilities, Inc. November 2, 1993.

_____. Docket No. 930880-WS. Southern States Utilities, Inc. September 13, 1994.

_____. Docket No. 930892-WU. Venture Associates Utilities Corp. December 30, 1994.

_____. Docket No. 931122-WU. Lakeside Golf, Inc. February 9, 1995

Hawaii

Hawaii Public Utilities Commission. Docket No. 6434. GASCO, Inc. April 3, 1992.

Illinois

Illinois Commerce Commission. Docket No. 92-0116. Illinois-American Water Company. February 9, 1993.

_____. Docket No. 94-0481. Citizens Utilities Company of Illinois. September 13, 1995.

_____. Docket No. 95-0076. Illinois-American Water Company. December 20, 1995.

Indiana

Indiana Utility Regulatory Commission. Cause No. 36483. Northern Indiana Fuel & Light Company, Inc. October 1, 1981.

_____. Cause No. 36427. Terre Haute Water Works Corp. November 13, 1981.

_____. Cause No. 38880. Indiana-American Water Company. September 26, 1990.

_____. Cause No. 39595. Indiana-American Water Company. February 2, 1994.

_____. Cause No. 40703. Indiana-American Water Company. December 11, 1997.

Iowa

Iowa Utilities Board. Docket No. RPU-94-2I. ES Utilities, Inc. June 30, 1995.

Maine

Maine Public Utilities Commission. Docket Nos. 91-193 and 93-027. Michael McGovern v. Portland Water District. February 28, 1994.

Maryland

Maryland Public Service Commission. Case No. 8643. Chesapeake Utilities Corp. August 17, 1994.

Massachusetts

Massachusetts Department of Public Utilities. D.P.U. 95-118. Massachusetts-American Water Company. May 31, 1996.

Missouri

Missouri Public Service Commission. Case No. 90-236. Missouri Cities Water Company. October 12, 1990.

_____. Case Nos. WR-95-205 and SR-95-206. Missouri-American Water Company. November 21, 1995.

_____. Case Nos. WR-95-205 and SR-95-206. Missouri-American Water Company. November 21, 1995.

_____. Case Nos. WR-97-237 and SR-97-238. Missouri-American Water Company. November 6, 1997.

New Hampshire

New Hampshire Public Utilities Commission. Docket DR 97-058. Pennichuck Water Works, Inc, Request for Permanent Rates. March 25, 1998.

New Jersey

New Jersey Board of Public Utilities. Docket No. WR95040165. New Jersey-American Water Company. March 3, 1996.

New York

New York Public Service Commission. Case No. 93-W-0962. Order Instituting Proceeding and Soliciting Comments, Investigation of Incentives for Acquisition and Merger of Small Water Utilities. November 10, 1993.

Ohio

Ohio Public Utilities Commission. Case Nos. 88-716-GA-AIR et. all, 88-1011-GA-CMR. Columbia Gas of Ohio, Inc. October 17, 1989.

Pennsylvania

Pennsylvania Public Utility Commission. Order in Docket R-850096, Western Pennsylvania Water Company (January 29, 1986).

_____. Order in Docket No. M-00950686. Policy Statement Re: Incentives For The Acquisition And Merger Of Small, Nonviable Water And Waste Water Systems. February 23, 1996.

Rhode Island

Rhode Island Public Utilities Commission. Docket No. 2216. Narragansett Bay Water Quality Management District. March 24, 1995.

Texas

Texas Public Utility Commission. Docket No. 4240. Texas-New Mexico Power Company. June 2, 1982.

West Virginia

West Virginia Public Service Commission. Case No. 81-126-W-42A. West Virginia Water Company. May 26, 1982.

_____. Case No. 89-498-W-42T. West Virginia-American Water Company. May 4, 1990.

_____. Case No. 89-498-W-42T. West Virginia-American Water Company. May 24, 1990.

_____. Case No. 93-0279-W-42T. West Virginia-American Water Company. January 23, 1994.

Source: Adapted and updated from Daniel W. McGill, "Memorandum on Single-Tariff Pricing" (correspondence dated December 31, 1996).

APPENDIX C
DETAILED EXAMPLE OF SINGLE-TARIFF PRICING

Table C1
Cost-of-Capital Determination

Source of Capital	Issuance Cost ($)	End-of-year Capitalization ($)	Capitalization (percent)	Cost Rate ($)	Weighted Cost ($)
Short-term bank debt		4,800,000	7.47	14.00	1,046
Long-term debt bonds					
First-mortgage bonds					
5 3/8% series due 3/1/82	2,040	2,500,000	3.90	5.427	0.211
9 3/4% series due 5/1/95	40,544	3,000,000	4.67	9.884	0.462
10% series due 10/1/96	229,017	16,800,000	26.17	10.116	2.647
9 3/8% series due 8/1/96	83,423	7,840,000	12.21	9.474	1.157
Total long-term debt		30,140,000	46.95	9.54	4.477
Preferred stock					
10 percent	31,781	2,940,000	4.58	10.092	0.462
9 1/2 percent	19,067	1,368,000	2.13	9.602	0.204
7 1/2 percent	21,926	1,920,000	2.99	7.692	0.230
Total preferred stock		6,228,000	9.70	9.24	8.896
Common equity					
Common stock		986,073			
Capital surplus		7,172,538			
Earned surplus		14,875,670			
Total common equity		23,034,281	35.88	15.00	5.381
Total capitalization		64,202,281	100.00		11.800

Source: Adapted from Edward M. Limbach, "Single Tariff Pricing," *Journal American Water Works Association* 75 no. 9 (September 1984).

Table C2
Allocation of Expenses by District and Under Single-Tariff Pricing

Expense Per 1 Million Gallons of Pumped Water	District A	District B	District C	District D	Single-Tariff Pricing
Fuel and power	49	91	115	102	57
Chemicals	15	31	76	17	20
Total operation cost	374	2,136	2,443	789	513
Total maintenance cost	103	499	277	94	116

Source: Adapted from Edward M. Limbach, "Single Tariff Pricing," *Journal American Water Works Association* 75 no. 9 (September 1984).

Table C3
District Revenue Requirements and Effect on Average Residential Water Bill

Cost and Service Characteristics	District A	District B	District C	District D
Ratebase ($)	52,231,951	211,630	351,510	2,320,677
Rate of return (percent) ◆	11.80	11.80	11.80	11.80
Utility operating income ($)	6,163,370	24,972	41,466	273,840
Operation & maintenance expense ($)	5,835,260	173,506	139,624	806,709
Depreciation & amortization ($)	806,306	5,931	9,750	32,509
Taxes other than federal income tax ($)	1,789,540	16,527	18,728	131,035
Provision for federal income tax ($)	1,057,772	2,919	2,944	45,127
Total revenue requirement ($)	15,652,248	223,855	212,512	1,289,220
Percentage of revenue assigned to residential customers	53.03	70.86	66.4	64.67
Number of residential customers	51,651	534	558	5,180
Average residential water bill ($)◆◆	12.01	27.70	24.21	13.30
Impact of $50,000 investment on average residential bill	0.12 (1%)	15.16 (55%)	$13.59 (56%)	$1.43 (11%)

Source: Adapted from Edward M. Limbach, "Single Tariff Pricing," *Journal American Water Works Association* 75 no. 9 (September 1984).
◆ From Table C1. ◆◆ Based on 4,500 gallons per month.

Table C4
Comparison of Tariffs for Selected Districts Before and After Implementation of Single-Tariff Pricing

Usage Charge	District A ($)	District B ($)	Single-Tariff Pricing ($)
Minimum charge			
17-mm (5/8-inch) meter or smaller	6.62	13.11	7.35
20-mm (3/4-inch) meter	9.78	19.67	11.06
25-mm (1-inch) meter	16.30	32.78	18.40
40-mm (1 1/2-inch) meter	32.59	65.56	36.80
50-mm (2-inch) meter	52.15	104.91	58.90
80-mm (3-inch) meter	97.78	196.70	110.40
100-mm (4-inch) meter	162.96	327.85	184.00
150-mm (6-inch) meter	325.92	655.69	368.00
200-mm (8-inch) meter	521.47	1,049.11	568.80
Variable charge (per 1,000 gallons)			
First 2000 gallons/month	--	--	--
Next 28,000 gallons/month	2.597	4.526	2.74
Next 970,000 gallons/month	1.562	3.147	1.56
Next 9 million gallons/month	1.107	3.147	1.14
All more than 10 million gallons/month	0.858	3.147	0.902

Source: Adapted from Edward M. Limbach, "Single Tariff Pricing," *Journal American Water Works Association* 75 no. 9 (September 1984).

APPENDIX D

Date: 1996

_____

(_____) _____
Dr. Janice A. Beecher, Director of Regulatory Studies
University

Re:

Happy New Year! Can you help me by taking a moment to fill out this quick survey and faxing it will make the results available to everyone.

is used to implement a single rate structure for multiple water (or other) utility the utility pay the same rate for service, even though the individual systems providing service may Water utilities with multiple systems are not necessarily found in every state.

1. Do any of the water **utilities** regulated by your commission have multiple water **systems** (☑)? **Yes** ❒ **No** ❒

   If No, the remaining questions are not applicable to your state. Please return the first page of the questionnaire so that your state will be represented in the survey.

2. If you answered **Yes** to Question 1, please name the multi-system water utilities, the number of systems they operate, and the approximate number of connections for the smallest and largest system operated by the utility. Use an additional sheet if necessary.

3.

Utility Name	*Total Number of Systems*	*Approximate Number of Connections for the: Smallest System*	*Largest System*

3. Has your commission **approved** single-tariff pricing for any of the utilities named in Question 1 (☑)? **Yes** ❒ *Go to Question 4* **No** ❒ *Go to Question 5*

4. If your answer to Question 3 was **Yes**, please name the utilities and when the tariff was first approved. Use an additional sheet if necessary.

Utility Name	*When was the tariff first approved?*
_____	_____
_____	_____
_____	_____

5. If your answer to Question 3 was **No**, please check all of the following that apply (☑):

- ❒ Single-tariff pricing has not been an issue.
- ❒ Single-tariff pricing has been considered but not specifically approved.
- ❒ A proposal for single-tariff pricing has been rejected.
- ❒ Other: _____

6. Has single-tariff pricing been explicitly **prohibited** in your state by statute (☑)? **Yes** ❒ **No** ❒

When was the statute passed? _____

Please describe the nature of the prohibition: _____

_____

_____

7. Has your commission put any monitoring and/or evaluation systems in place for single-tariff pricing in cases where it has been implemented (☑)? **Yes** ❒ **No** ❒

If **Yes**, please describe: _____

_____

8. If your commission **approved** single-tariff pricing, what was the **primary** reason for the approval? _____

9. If your commission **rejected** single-tariff pricing, what was the **primary** reason for the rejection? _____

10. Please characterize your commission's policy position on single-tariff pricing (☑)?
✓
- ❒ Generally accepted
- ❒ Generally not accepted
- ❒ Decided on a case-by-case basis
- ❒ Never considered

11. If single-tariff pricing has been an issue in your state, whether or not it has been implemented, please review the following arguments in favor and against single-tariff pricing and check all that have influenced your commission's deliberations or policies on the issue. Check (☑) all that apply:

Arguments in Favor of Single-Tariff Pricing

✓

- ❒ Provides incentives for utility regionalization and consolidation
- ❒ Mitigates rate shock to utility customers
- ❒ Promotes universal service for utility customers
- ❒ Promotes ratepayer equity on a regional basis
- ❒ Improves service affordability for customers
- ❒ Addresses small-system viability issues
- ❒ Facilitates compliance with drinking water standards
- ❒ Provides ratemaking treatment that is similar to that for other utilities
- ❒ Lowers administrative costs to the utilities
- ❒ Lowers administrative costs to the commission
- ❒ Promotes regional economic development
- ❒ Encourages further private involvement in the water sector
- ❒ Encourages investment in the water-supply infrastructure
- ❒ Physical interconnection is not considered a prerequisite
- ❒ Overall benefits outweigh overall costs
- ❒ Other: _____

Arguments Against Single-Tariff Pricing

✓

- ❒ Conflicts with cost-of-service principles
- ❒ Undermines economic efficiency
- ❒ Provides subsidies to high-cost customers
- ❒ Distorts price signals to customers
- ❒ Discourages efficient water-use and conservation
- ❒ Encourages growth and development in high-cost areas
- ❒ Encourages overinvestment in infrastructure
- ❒ Fails to account for variations in customer contributions
- ❒ Provides unnecessary incentives to utilities
- ❒ Considered inappropriate without physical interconnection
- ❒ Not acceptable to all affected customers
- ❒ Not acceptable to other agencies or governments
- ❒ Justification has not been adequate in a specific case (or cases)
- ❒ Insufficient statutory or regulatory basis or precedents
- ❒ Overall costs outweigh overall benefits
- ❒ Other: _____

Please provide any additional comments on another sheet. Thank you again for your assistance. I look forward to working with you in 1996.

APPENDIX E
DETAILED FINDINGS FROM COMMISSION SURVEY ON SINGLE-TARIFF PRICING

TABLE E1
Commission Policies on Single-Tariff Pricing for Water Utilities

State	Multi-System Utilities in the State (Q1)	Number of Multi-System Utilities (Q2)	Commission Approval of Single-Tariff Pricing (Q3)	Number of Utilities with Single Tariff Pricing (Q4)	Reasons for No Single-Tariff Pricing (Q5)	Has Single-Tariff Pricing Been Prohibited by Statute (Q6)	Monitor or Evaluate Single-Tariff Pricing (Q7)	Reason for Approval (Q8)	Reason for Rejection (Q9)	Commission Policy (Q10)
Alabama	No	0	NA	NA	NA	NA	NA	NA	NA	NA
Alaska	No	0	NA	NA	NA	NA	NA	NA	NA	NA
Arizona	Yes	9	Yes	2	NA	No	No	Viability of systems	NA	Case-by-case
Arkansas	No	0	NA	NA	NA	NA	NA	NA	NA	NA
California	Yes	3	No (a)	0 (a)	Considered but not approved	No	No	NA	NA	Case-by-case
Colorado	No	0	NA	NA	NA	NA	NA	NA	NA	NA
Connecticut	Yes	12	Yes	10	NA	No	No	Mitigate rate shock	NA	Generally accepted
Delaware (b)	No	0	No	NA	NA	NA	NA	NA	NA	NA
Florida	Yes	60 to 70	Yes	20	NA	No (c)	No	Affordability; revenue stability; rate normalization for construction projects; simplified bookkeeping; reduced rate case expense.	NA	Case-by-case
Georgia	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Hawaii	No	0	NA	NA	NA	NA	NA	NA	NA	NA
Idaho	Yes	1	Yes	1	NA	No	No	Not an issue when proposed	NA	Case-by-case
Illinois	Yes	4	Yes	2	NA	No	No	Reasonably consistent costs and source of supply.	Difference in source-of-supply costs	Case-by-case

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Indiana	Yes	2	No	0	Rejected (later approved)	No	NA	NA	Cost-of-service; cost-based rates	Case-by-case
Iowa	Yes	1	No	0	Not an issue	No	NA	NA	NA	Never considered
Kansas	No	0	NA	NA	NA	NA	NA	NA	NA	NA
Kentucky	Yes	1	No	0	Not an issue	No (d)	NA	NA	NA (d)	Never considered
Louisiana	Yes	10	No	0	Not an issue	No	NA	NA	NA	Never considered
Maine	Yes	1	No	0	Not an issue	No	NA	NA	NA	Never considered
Maryland	Yes	2	No	0	Not an issue	No	NA	NA	NA	Case-by-case
Massachusetts	Yes	1	No (a)	0 (a)	Considered but not approved*	No	No	Contiguity of communities; commonality of personnel; administrative convenience.	Need for further post-merger experience.	Case-by-case
Michigan	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Minnesota	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Mississippi	Yes	1	No	NA	Not an issue	No	NA	NA	NA	Case-by-case
Missouri	Yes	2	Yes	2	NA	No	No	Cost savings	NA	Generally accepted
Montana (b)	No	0	NA	NA	NA	NA	NA	NA	NA	NA
Nebraska	No	0	NA	NA	NA	NA	NA	NA	NA	NA
Nevada	No	0	NA	NA	NA	NA	NA	NA	NA	NA
New Hampshire	Yes	4	No (a)	0 (a)	Considered but not approved*	No	NA	NA	NA	Case-by-case

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State	Multi-System Utilities in the State (Q1)	Number of Multi-System Utilities (Q2)	Commission Approval of Single-Tariff Pricing (Q3)	Number of Utilities with Single Tariff Pricing (Q4)	Reasons for No Single-Tariff Pricing (Q5)	Has Single-Tariff Pricing Been Prohibited by Statute (Q6)	Monitor or Evaluate Single-Tariff Pricing (Q7)	Reason for Approval (Q8)	Reason for Rejection (Q9)	Commission Policy (Q10)
New Jersey	Yes	3	No	0	Considered but not approved*	No	NA	NA	NA	Case-by-case
New Mexico	No	0	NA	NA	NA	NA	NA	NA	NA	NA
New York	Yes	5	Yes	1	NA	No	No	Acceptable cost-of-service differentials	Cost-of-service differentials	Case-by-case
North Carolina	Yes	50	Yes	46	NA	No	No	More economical for utility and customers; less tracking required.	NA	Generally accepted
North Dakota	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Ohio	Yes	3	Yes	2	NA	No	No	Company request, cost savings, customer benefits.	NA	Case-by-case
Oklahoma	No	0	NA	NA	NA	NA	NA	NA	NA	NA
Oregon	Yes	1	Yes	1	NA	No	No	Public interest	NA	Generally accepted
Pennsylvania (e)	Yes	11	Yes	7	NA	No	No	Economies of scale; mitigate rate shock associated with improvements; lessen bookkeeping and reporting.	NA	Generally accepted; case-by-case
Rhode Island	No	0	NA	NA	NA	NA	NA	NA	NA	NA

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South Carolina	Yes	4	Yes	4	NA	No	No	Uniform cost allocation; lower billing costs; base charge covers most fixed costs.	NA	Generally accepted
South Dakota	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Tennessee	No	0	NA	NA	NA	NA	NA	NA	NA	NA
Texas	Yes	200 to 300	Yes	Most	NA	No	No	Regionalization, lower administrative cost	NA	Generally accepted and preferred
Utah	No	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vermont	Yes	1	Yes	1	NA	No	NA	Viability of systems; public interest	Staff rejected based on cross subsidies	Case-by-case
Virginia	Yes	4	Yes	4	NA	No	No	Spreads costs; separating small-system costs not always effective.	NA	Case-by-case
Washington	Yes	30	Yes	25	NA	No	No	Economies of scale for small systems	NA	Generally accepted

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West Virginia (f)	Yes	26	Yes	17	NA	No	Yes (g)	Promotes regionalization; ratepayer equity; ratemaking treatment similarity (f).	Cost-of-service principles; customer contribution inequities (f).	Case-by-case
Wisconsin (h)	Yes	1	No	0	Not an issue	No	NA	NA	NA	Never considered
Wyoming (b)	No	NA	NA	NA	NA	NA	NA	NA	NA	NA
D.C.	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ

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(a) Partial rate consolidation has been approved; single-tariff pricing may be phased-in for some utilities (for regulatory simplification).
(b) Response by phone or derived from *1995 Inventory of Commission-Regulated Water Systems;* no multi-system water utilities.
(c) Proposed legislation would require physical interconnection of systems for single-tariff pricing.
(d) Farmers Home Administration debt requirements prohibit, but the issue did not come before the commission.
(e) May be more multi-system water utilities in the state.
(f) The commission regulates public service districts. These data reflect primarily the views of staff involved in regulating the districts.
(g) Reevaluation of rate cases where single-tariff pricing has been implemented (for public service districts).
(h) Response applies to regulated investor-owned utilities only. The Commission also regulates municipal water utilities and state law requires single-tariff pricing throughout municipalities.
* Pending or later cases were decided in favor of single-tariff pricing.

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Summary Data										
Yes	29	--	17	--	--	0	1	--	--	--
No	16	--	13	--	--	29	17	--	--	--
NA	0	--	15	--	33	16	27	27	38	16
NJ	6	--	6	--	6	6	6	6	6	6
Not an issue	--	--	--	--	7	--	--	--	--	--
Rejected	--	--	--	--	1	--	--	--	--	--
Considered but not approved	--	--	--	--	4	--	--	--	--	--
Generally accepted	--	--	--	--	--	--	--	--	--	8
Generally not accepted	--	--	--	--	--	--	--	--	--	0
Case-by-case	--	--	--	--	--	--	--	--	--	16
Never considered	--	--	--	--	--	--	--	--	--	5
Total	51	193	51	145	51	51	51			51

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TABLE E2
Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
Alabama	NA	NA	NA	NA	NA	NA	
Alaska	NA	NA	NA	NA	NA	NA	
Arizona	Wilhoit Water Company	4	47	140	Yes	1993	
	Water Utility of Greater Tonopah, Inc.	7	4	67	Yes	1994	
	Arizona Water Company	20	176	8,120	No	NA	
	Big Park Water Company	3	10	1,400	No	NA	
	Citizens Utilities Company	5	416	20,000	No	NA	
	Congress Water Company	2	48	434	No	NA	
	Cordes Lakes Water Company	3	600	2,977	No	NA	
	Marana Water Service, Inc.	2	88	600	No	NA	
	United Utilities	12	22	1,229	No	NA	
Arkansas	NA	NA	NA	NA	NA	NA	
California	Cal Water Service Company	19	485	3,400	Partial	1990s	Phasing-in tariff, subject to cost analysis (a).
	Southern California Water Company	21	1,000	96,000	Partial	1990s	Phasing-in tariff, subject to cost analysis (a).
	California-American Water Company	5	7,000	40,000	No	NA	
Colorado	NA	NA	NA	NA	NA	NA	
Connecticut	Bridgeport Hydraulic Company	7	66	97,000	Yes	1986	
	Connecticut Water Company	16	42	27,000	Yes	1988	
	Connecticut-American Water Company	5	43	16,000	Partial	1985	Phasing-in rate.
	Crystal Water Company	3	480	2,204	Yes	1995	
	Eastern Connecticut Regional Water Co.	25	<5	249	Partial	1993	Six tariffs; phasing-in rate.
	Gallup Water Service Company	4	36	574	No	NA	

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State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
	Jewett City Water Company	4	20	1,331	Yes	1986	
	Olmstead Water Company	4	31	121	Yes	1995	
	Rural Water Company	20	2	244	Yes	1973	
	Topstone Hydraulic Company	3	41	237	Yes	1975	
	Tyler Lake Water Company	4	27	90	No	NA	
	United Water Connecticut Inc.	4	136	2,919	Yes	1993	
Delaware	NA	NA	NA	NA	NA	NA	Since the survey, a multi-system utility was created (acquisition); consolidated rates were approved.
Florida (b)	Arredondo Utility Company	2	NR	NR	Yes	NR (b)	
	Clay Utility Company	2	NR	NR	Yes	NR (b)	
	Consolidated Water Works, Inc.	2	NR	NR	Yes	NR (b)	
	Florida Cities Water Company (Lee County)	2	NR	NR	Yes	NR (b)	Single-tariff for water only.
	Gulf Utility Company	2	NR	NR	Yes	NR (b)	Interconnected water; noninterconnected wastewater.
	Heartland Utilities, Inc	2	NR	NR	Yes	NR (b)	
	Holiday Utility Company, Inc.	2	NR	NR	Yes	NR (b)	
	Jacksonville Suburban Utilities Corp., Inc.	21	NR	NR	Partial	NR (b)	Three tariffs.
	Lake Utility Services, Inc.	11	NR	NR	Partial	NR (b)	Two tariffs.
	Lenvil H. Dicks	4	NR	NR	Yes	NR (b)	
	Mad Hatter Utility, Inc.	3	NR	NR	Yes	NR (b)	Noninterconnected water; interconnected wastewater.

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State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
	Marion Utilities, Inc.	23	NR	NR	Partial	NR (b)	Two tariffs.
	Neighborhood Utilities, Inc.	5	NR	NR	Yes	NR (b)	
	Ocala Oaks Utilities, Inc.	9	NR	NR	Yes	NR (b)	
	Pine Island Utility Corporation	2	NR	NR	Yes	NR (b)	
	Poinciana Utilities, Inc.	4	NR	NR	Yes	NR (b)	
	Rainbow Springs Utilities, Inc.	2	NR	NR	Yes	NR (b)	
	Seven Rivers Utilities, Inc.	3	NR	NR	Yes	NR (b)	
	Sunshine Utilities of Florida	20	NR	NR	Partial	NR (b)	Excludes 2 systems.
	Utilities, Inc.	16	NR	NR	Partial	NR (b)	Three tariffs.
Georgia	NJ	NJ	NJ	NJ	NJ	NJ	
Hawaii	NA	NA	NA	NA	NA	NA	
Idaho	Hayden Pines Water Company	10	12	646	Yes	1985	Not an issue when proposed.
Illinois	Citizens Utilities Company of Illinois	22	114	8,400	Partial	1965	Some exceptions based on source of supply differences.
	Illinois-American Water Company	5	1,700	65,200	Partial	1993	Phasing-in one system.
	Northern Illinois Water Corporation	4	4,000	40,200	No	NA	
	Consumers Illinois Water Company	8	200	19,200	No	NA	
Indiana	Indiana-American Water Company	16	NR	NR	No	NA	
	Hoosier Water	4	NR	NR	No	NA	
Iowa	Iowa-American Water Company	2	10,400	43,700	No	NA	
Kansas	NA	NA	NA	NA	NA	NA	
Kentucky	Southeastern W.D.	3	837	1,278	No	NA	
Louisiana	A.T.S.	NR	NR	NR	No	NA	
	Acadian Water & Sewer	NR	NR	NR	No	NA	

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Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
	Baton Rouge Water Company	NR	NR	NR	No	NA	
	Capital Utilities	NR	NR	NR	No	NA	
	Coast Water System	NR	NR	NR	No	NA	
	Hunstock Hills	NR	NR	NR	No	NA	
	Ascension Water Company	NR	NR	NR	No	NA	
	Louisiana Water Company	NR	NR	NR	No	NA	
	Parish Water Company	NR	NR	NR	No	NA	
	Utilities Data, Inc.	NR	NR	NR	No	NA	
Maine	Consumers Maine Water Company	7	408	7,192	No	NA	
Maryland	Utilities, Inc.	5	75	1,010	No	NA	
	Facilities Services, Inc.	7	31	130	No	NA	
Massachusetts	Massachusetts-American	3	2,400	11,000	Partial	1990	Two tariffs under a settlement agreement; a case is pending (a).*
Michigan	NJ	NJ	NJ	NJ	NJ	NJ	
Minnesota	NJ	NJ	NJ	NJ	NJ	NJ	
Mississippi	Johnson Utility Company	32	12 to 15	600 to 750	No	NA	
Missouri	Missouri-American Water	7	500	2,800	Yes	1995	
	KMB Utilities	6	200	600	Yes	1995	
Montana	NA	NA	NA	NA	NA	NA	
Nebraska	NA	NA	NA	NA	NA	NA	
Nevada	NA	NA	NA	NA	NA	NA	

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TABLE E2
Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
New Hampshire	Consumers New Hampshire Water	24	40	5,000	Partial	NR	Three tariffs; may be moving toward single tariff (a).
	Pennichuck Water Works	12	35	19,000	No	NA	
	Lakes Regional Water Company	11	30	200	No	NA	
	Carleton Water Company	4	30	175	No	NA	
New Jersey	New Jersey-American	2	272	329,000	No	NA	A case is pending.*
	Elizabethtown Water Company	2	10,928	181,100	No	NA	
	Consumers New Jersey	7	422	28,652	No	NA	
New Mexico	NA	NA	NA	NA	NA	NA	
New York	Jamaica Water Supply	2	30,000	90,000	No	NA	Operated as one system until disconnected and extreme cost differentials became apparent
	South County Water	4	2	270	No	NA	Smallest serves two industrial customers.
	Rand Water	2	148	158	No	NA	
	Northwood Water	2	49	220	No	NA	
	Forest Park Water	6	30	60	Yes	1987	Commission imposed single-tariff pricing.
North Carolina	Alpha Utilities	11	18	121	Yes	1986	
	Bess Brothers	11	16	78	Yes	1971	
	Bogue Banks Water Company	3	80	3,830	Yes	1991	
	Bradshaw Water Company	5	10	41	Yes	1974	
	Brookwood Water Corporation	15	32	5,345	Yes	1974	

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Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
	Carolina Water Services of NC	72	13	2,790	Yes	1978	
	Clear Meadow Water	2	24	50	Yes	1981	
	Coastal Plains Utility Company	3	36	542	Yes	1967	
	Community Water Works	2	26	51	Yes	1975	
	Corriher Water Service	22	13	193	Yes	1968	
	Crabtree Water Systems	3	10	26	No	NA	
	Cross State Development Company	3	9	140	Yes	1974	
	CWS Systems	16	12	1,211	No	NA	
	D&W Water Systems	2	17	96	Yes	1987	
	Environmental Maintenance	3	20	132	No	NA	
	Fairways Utilities	3	9	296	Yes	1990	
	Fisher Utilities	18	13	184	Yes	1973	
	Fox Run Water Company	6	21	60	Yes	1989	
	Goss Utility Company	7	19	131	Yes	1976	
	Grandfather Golf and Country	2	45	156	Yes	1982	
	Heater Utilities	150	10	2,475	Yes	1972	
	Wayne M. Honeycutt	3	15	40	Yes	1978	
	Huffman Water Systems	10	11	83	Yes	1964	
	Hydraulics, Ltd.	85	4	191	Yes	1966	
	HydroLogic	4	15	64	No	NA	
	Kings Grant Water Company	7	96	850	Yes	1968	
	Knob Creek Utility	3	24	151	Yes	1984	
	Language Water Works Corp.	22	62	678	Yes	1969	
	Ira D. Lee & Assoc.	2	41	145	Yes	1986	

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TABLE E2
Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
	Lewis Water Company	14	6	80	Yes	1980	
	Lincoln Water Works	2	21	122	Yes	1972	
	William K. Mauney	2	19	24	Yes	1976	
	Mercer Environmental	10	47	479	Yes	1965	
	Mid South Water Systems	201	7	429	Yes	1981	
	Giles E. Mullis	2	20	20	Yes	1983	
	Norwood Beach Water System	4	10	36	Yes	1995	
	Piedmont Construction & Water	47	7	147	Yes	1970	
	Prior Construction Company	2	11	184	Yes	1988	
	Quality Water Supplies	14	37	257	Yes	1967	
	Rayco Utilities	10	12	104	Yes	1987	
	Scientific Water & Sewage	5	106	537	Yes	1964	
	Scotland Water	4	39	91	Yes	1983	
	Scotsdale Water & Sewage	15	7	205	Yes	1990	
	Setzer Brothers Well Boring	3	30	72	Yes	1972	
	Spring Water Company	2	17	139	Yes	1977	
	Surry Water Company	30	8	206	Yes	1972	
	Turner Farms	4	20	127	Yes	1982	
	Water Resources	2	9	81	Yes	1993	
	West Wilson Water Company	6	15	74	Yes	1988	
	Woods Water Works	4	5	18	Yes	1981	
North Dakota	NJ	NJ	NJ	NJ	NJ	NJ	
Ohio	Ohio-American Water	8 or 9	300	15,000	Yes	1975 to 1983	

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TABLE E2
Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
	Citizens Utilities	6	278	3,023	Yes	1975 to 1983	
	Consumers Ohio Water	4	7,516	25,254	No	NA	
Oklahoma	NA	NA	NA	NA	NA	NA	
Oregon	Avion Water Company, Inc.	4	52	5,750	Yes	Early 1970s	
Pennsylvania	Pennsyvania-American Water Company	27	NR	NR	Yes	1970s & 1980s	Interconnected systems (1970s); noncontiguous systems (1980s).
	United Water Pennsylvania, Inc.	22	NR	NR	Partial	1992	Excludes one system.
	Consumers Pennsylvania Water Company	10	NR	NR	Partial	NR	Three rate zones.
	Citizens Utilities Water Company of PA	20	NR	NR	Partial	NR	Five rate zones.
	National Utilities, Inc.	21	NR	NR	Partial	NR	Three rates and four systems with their own tariffs.
	Philadelphia Suburban Water Company	15	NR	NR	Partial	NR	Most acquisitions adopt the single tariff; excludes two systems.
	Newtown Artesian Water Company	2	NR	NR	Yes	1994	Merger of two companies.
	Redstone Water Compnay, Inc.	3	NR	NR	No	NA	Three rate zones and four systems with separate tariffs.
	Frank Sargent	4 to 5	NR	NR	No	NA	May be moving toward single tariff.
	Blaine Rhodes	5	NR	NR	No	NA	May be moving toward single tariff.

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TABLE E2
Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
	Carl Kreisge	2 to 3	NR	NR	No	NA	May be moving toward single tariff.
Rhode Island	NA	NA	NA	NA	NA	NA	
South Carolina	Carolina Water Service Inc.	53	18	1,500	Yes	1987	
	Heater Utilities, Inc.	38	5	250	Yes	1990	
	Blue Ribbon H2O Corporation	34	5	300	Yes	1995	
	Upstate Heater Utilities Inc.	21	20	50	Yes	1994	
South Dakota	NJ	NJ	NJ	NJ	NJ	NJ	
Tennessee	NA	NA	NA	NA	NA	NA	
Texas	*Data not easily available*	----------*Not reported*----------					*Single-tariff pricing is preferred; a special procedure is used to implement the tariff in conjunction with acquisitions.*
Utah	NA	NA	NA	NA	NA	NA	
Vermont	Sunshine Water Company	4	12	40	Yes	1985	
Virginia	Alpha Water Corporation	28	10	200	Yes	1984	
	Heritage Homes of Virginia	8	11	29	Yes	1994	
	New River Water Company	14	7	126	Yes	1993	
	Pocahontas Water Works	2	60	68	Yes	1958	
Washington (c)	Alderton-McMillin Water Supply, Inc.	8	NR	NR	Yes	NR	
	Aquarius Utilities, Inc.	4	NR	NR	Yes	NR	
	Arcadia Utilities	11	NR	NR	No	NA	
	Bethel Water Company	3	NR	NR	Yes	NR	

NA = Not applicable; NR = Not reported; NJ = No jurisdiction

TABLE E2
Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
	Evergreen Land & Water, Inc.	6	NR	NR	Yes	NR	System under receivership.
	Gamble Bay Water, Inc.	10	NR	NR	Yes	NR	
	H & R WaterWorks, Inc.	8	NR	NR	Yes	NR	
	H2O Company, The	2	NR	NR	No	NA	
	Harbor Water Company, Inc.	79	NR	NR	Yes	NR	
	Iliad Water Services, Inc.	12	NR	NR	No	NA	
	Lara Lee, Inc.	6	NR	NR	Yes	NR	
	Mainland View Manor Maintenance Co.	5	NR	NR	Yes	NR	
	Marvin Road Water Company	4	NR	NR	Yes	NR	
	Mirrormont Srevices, Inc.	2	NR	NR	Yes	NR	
	Monterra, Inc. (Washington Water Systems)	2	NR	NR	Yes	NR	
	Northwest Water Systems, Inc.	13	NR	NR	Yes	NR	
	Pattison Water Comapny	4	NR	NR	Yes	NR	
	Point Fosdick Water Company, Inc.	4	NR	NR	Yes	NR	
	Rainier View Water Company, Inc.	4	NR	NR	Partial	NR	Excludes 1-2 systems.
	Sanderson & Associates, Inc.	13	NR	NR	Yes	NR	
	Satellite Water Systems	25	NR	NR	No	NA	
	S-K Pump & Drilling	39	NR	NR	Yes	NR	
	Soren Pedersen Water Company	2	NR	NR	No	NA	
	Sound Water Company, Inc.	4	NR	NR	Yes	NR	
	South Bainbridge Water System, Inc.	2	NR	NR	Yes	NR	
	South Sound Utility Company, Inc.	35	NR	NR	Yes	NR	
	Stroh Water Company	5	NR	NR	Partial	NR	Excludes 1-2 systems.
	Sunshine Acres Water System	4	NR	NR	Yes	NR	

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TABLE E2
Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
	Thomas Water Service, Inc.	2	NR	NR	Yes	NR	
	Washington Water Supply, Inc.	9	NR	NR	Yes	NR	
West Virginia (d)	West Virginia-American	13	571	68,636	Yes	1982	Formerly 12 to 14 districts.
	Arbuckle	2	NR	NR	Yes	Prior to 8/85	
	Central Hampshire	2	NR	NR	No	NA	
	Friendly	2	NR	NR	Yes	Prior to 4/88	
	Gilmer County	2	NR	NR	Yes	Prior to	
	Grant County	2	NR	NR	Yes	Prior to 9/83	
	Green Valley-Glenwood	2	NR	NR	Yes	Prior to 6/80	
	Hammond	2	NR	NR	Yes	1982	
	Hardy County	2	NR	NR	No	NA	
	Jefferson County	3	NR	NR	No	NA	
	Kopperston	2	NR	NR	Yes	1981	
	Logan County	5	NR	NR	Yes	1995	
	Mannington	2	NR	NR	Yes	Prior to 3/82	
	Mason County	3	NR	NR	No	NA	
	McDowell County	6	NR	NR	No	NA	
	Oakland	2	NR	NR	Yes	Prior to 5/84	
	Ohio County	3	NR	NR	Yes	Prior to 1/81	
	Pendleton County	4	NR	NR	No	NA	
	Preston County #1	2	NR	NR	Yes	Prior to 2/81	
	Preston County #2	2	NR	NR	Yes	Prior to	
	Raleigh County	3	NR	NR	No	NA	
	Red Sulphur	2	NR	NR	Yes	Prior to 8/83	

NA = Not applicable; NR = Not reported; NJ = No jurisdiction

TABLE E2
Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
	South Putnam	2	NR	NR	No	NA	
	Van	2	NR	NR	No	NA	
	Washington Pike	2	NR	NR	Yes	Prior to 7/80	
	Wyoming-Glover	2	NR	NR	Yes	Prior to 2/85	
Wisconsin	Wisconsin Power & Light	2	2,661	13,752	No	NA	
	Several towns with two or three systems	----------*Not reported*----------					*Single-tariff pricing is required for municipal utilities.*
Wyoming	NA	NA	NA	NA	NA	NA	
D.C.	NJ	NJ	NJ	NJ	NJ	NJ	

(a) Single-tariff pricing has not been explictly approved, but some rate consolidation has occurred (three states; four systems).
(b) Only utilities with single-tariff pricing for all or some systems are reported. These rates were approved over time, dating back to at least the early 1980s. Data were not reported for all multi-system utilities in the state.
(c) Flat rates and metered rates may exist within the same tariff; mobile home parks and multi-dwelling units may have a separate rate within the same tariff.
(d) Only West-Virginia is investor-owned; the rest are public service districts. Only multi-system utilities are reported;interconnected systems and single-systems with multiple tariffs are not included.
* Pending cases were decided in favor of single-tariff pricing.

NA = Not applicable; NR = Not reported; NJ = No jurisdiction

TABLE E2
Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
Summary Data for All Utilities							
Yes		--	--	--	129	--	
Partial		--	--	--	20	--	
No		--	--	--	64	--	
Total	--		--	--	213	--	
Minimum		2	2	18	--	--	
Maximum		201	30,000	329,000	--	--	
Average		11	751	11,615	--	--	
Median		4	30	257	--	--	
Utilities reported		203	115	115	--	--	

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TABLE E2
Multi-System Water Utilities and Single-Tariff Pricing

State	Name of Multi-System Water Utility (Q2)	Approximate Number of Systems (Q2)	Smallest System (N Connections) (Q2)	Largest System (N Connections) (Q2)	Single-Tariff Pricing Approved (Q4)	Approximate Date of Approval (Q4)	Notes
Summary Data for Single-Tariff Utilities							
Yes		--	--	--	129	--	
Partial	--		--	--	20	--	
No		--	--	--	0	--	
Total		--	--	--	149	--	
Minimum		2	2	18	--	1958	
Maximum		201	2,400	97,000	--	1995	
Average		13	122	5,651	--	1982	
Median		5	20	193	--	1984	
Utilities reported		149	81	81	--	80	
Summary Data for Non-Single-Tariff Utilities							
Yes		--	--	--	0	--	
Partial		--	--	--	0	--	
No		--	--	--	64	--	
Total		--	--	--	0	--	
Minimum		2	2	26	--	--	
Maximum		32	30,000	329,000	--	--	
Average		6	2,251	25,824	--	--	
Median		4	82	1,254	--	--	
Utilities reported		54	34	34	--	--	

Note:
For reponses reported as a range of values, averages were used (for example, "8 to 9" was averaged to "8.5").
For the response "< 5" a value of 4.5 was used.

NA = Not applicable; NR = Not reported; NJ = No jurisdiction

TABLE E3
Arguments in Favor of Single-Tariff Pricing (a)

State	Regionalization Incentives	Mitigates Rate Shock	Universal Service	Regional Ratepayer Equity	Service Affordability	Small-System Viability	Compliance with Standards	Similar Ratemaking to Other Utilities	Lowers Admin. Costs to Utility	Lowers Admin. Costs to Commission	Regional Economic Development	Encourages Private Involvement	Encourages Investment	Interconnection Not Required	Overall Benefits Outweigh Costs	Other	Number of "Yes" Responses
Alabama	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Alaska	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Arizona	Yes	Yes	No	No	No	Yes	No	Yes	Yes	Yes	No	No	No	Yes	Yes	No	8
Arkansas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
California	No	Yes	Yes	No	Yes	Yes	No	No	No	No	No	No	No	No	No	No	4
Colorado	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Connecticut	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No	14
Delaware	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Florida	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No	13
Georgia	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Hawaii	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Idaho	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Illinois	Yes	Yes	No	No	No	No	Yes	No	Yes	No	No	No	No	Yes	Yes	No	6
Indiana	No	Yes	No	No	No	No	No	Yes	No	No	No	No	No	No	No	No	2
Iowa	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Kansas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Kentucky	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Louisiana	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Maine	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Maryland	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Massachusetts	No	No	No	Yes	No	No	No	No	Yes	No	No	No	No	Yes	No	No	3
Michigan	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Minnesota	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Mississippi	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Missouri	Yes	Yes	Yes	No	No	No	No	No	Yes	Yes	No	No	Yes	Yes	No	No	7
Montana	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

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TABLE E3
Arguments in Favor of Single-Tariff Pricing (a)

State	Regionalization Incentives	Mitigates Rate Shock	Universal Service	Regional Ratepayer Equity	Service Affordability	Small-System Viability	Compliance with Standards	Similar Ratemaking to Other Utilities	Lowers Admin. Costs to Utility	Lowers Admin. Costs to Commission	Regional Economic Development	Encourages Private Involvement	Encourages Investment	Interconnection Not Required	Overall Benefits Outweigh Costs	Other	Number of "Yes" Responses
Nebraska	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nevada	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
New Hampshire	Yes	Yes	No	No	Yes	Yes	No	No	No	No	No	No	No	No	No	No	4
New Jersey	Yes	Yes	No	No	No	Yes	Yes	Yes	Yes	No	Yes	No	No	Yes	No	No	8
New Mexico	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
New York	No	No	No	No	No	No	No	No	Yes	No	No	No	No	Yes	No	Yes (b)	3
North Carolina	Yes	Yes	No	No	Yes	Yes	Yes	No	Yes	No	Yes	No	No	Yes	Yes	No	9
North Dakota	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Ohio	Yes	Yes	No	No	Yes	Yes	No	No	Yes	No	No	No	No	Yes	No	No	6
Oklahoma	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Oregon	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	No	Yes	No	12
Pennsylvania	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	No	No	No	Yes	Yes	No	11
Rhode Island	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
South Carolina	No	Yes	Yes	No	No	No	No	Yes	Yes	No	No	No	No	No	No	No	4
South Dakota	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Tennessee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Texas	Yes	Yes	No	No	Yes	Yes	Yes	No	Yes	No	No	No	No	No	No	No	6
Utah	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vermont	No	No	No	No	No	Yes	No	No	No	No	No	No	No	No	No	Yes (c)	1
Virginia	Yes	Yes	No	No	Yes	No	No	Yes	Yes	Yes	No	No	No	No	No	No	6
Washington	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	No	14
West Virginia	Yes	No	No	Yes	Yes	No	No	Yes	No	No	No	No	No	Yes	Yes	No	6
Wisconsin	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Wyoming	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
D.C.	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ

NA = Not applicable; NR = Not reported; NJ = No jurisdiction

TABLE E3
Arguments in Favor of Single-Tariff Pricing (a)

State	Regionalization Incentives	Mitigates Rate Shock	Universal Service	Regional Ratepayer Equity	Service Affordability	Small-System Viability	Compliance with Standards	Similar Ratemaking to Other Utilities	Lowers Admin. Costs to Utility	Lowers Admin. Costs to Commission	Regional Economic Development	Encourages Private Involvement	Encourages Investment	Interconnection Not Required	Overall Benefits Outweigh Costs	Other	Number of "Yes" Responses
Summary Data																	
Yes	15	17	8	6	12	13	9	10	16	8	3	2	5	13	9	2	--
No	6	4	13	15	9	8	12	11	5	13	18	19	16	8	12	19	--
Not an issue	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	--
Not applciable	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	--
No jurisidction	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	--
Total	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	--

(a) These findings reflect staff views about the arguments affecting commission deliberations or policies.
(b) Can be consistent with cost-of-service principles.
(c) The board determined that single-tariff pricing was in the public interest and approved it over the objections of staff concerns about subsidies.

NA = Not applicable; NR = Not reported; NJ = No jurisdiction

TABLE E4
Arguments Against Single-Tariff Pricing (a)

State	Conflict with Cost-of-Service	Undermines Economic Efficiency	Subsidies to High-Cost Customers	Distorts Price Signals	Discourages Efficient Water Use	Encourages Growth in High-Cost Areas	Encourages Overinvestment	Fails to Account for Contributions	Unnecessary Incentives	Inappropriate Without Interconnection	Not Acceptable to All Customers	Not Acceptable to Agencies	Not Justified in a Specific Case	Insufficient Precedents	Overall Costs Outweigh Benefits	Other	Number of "Yes" Responses
Alabama	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Alaska	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Arizona	Yes	No	Yes	No	No	Yes	No	No	No	Yes	Yes	No	No	No	No	No	5
Arkansas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
California	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No	Yes	No	No	No	No	7
Colorado	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Connecticut	Yes	No	Yes	No	No	Yes	No	No	No	Yes	Yes	No	No	Yes	No	No	6
Delaware	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Florida	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	15
Georgia	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Hawaii	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Idaho	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Illinois	Yes	No	No	No	No	No	No	No	No	No	No	No	Yes	No	Yes	No	3
Indiana	Yes	No	No	No	No	No	No	Yes	No	No	Yes	No	Yes	No	No	No	4
Iowa	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Kansas	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Kentucky	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Louisiana	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Maine	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Maryland	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Massachusetts	Yes	No	No	No	No	No	No	No	No	Yes	No	No	Yes	No	No	No	3
Michigan	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Minnesota	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Mississippi	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Missouri	Yes	No	Yes	Yes	No	No	No	Yes	No	Yes	No	No	No	No	No	No	5
Montana	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

NA = Not applicable; NR = Not reported; NJ = No jurisdiction

TABLE E4
Arguments Against Single-Tariff Pricing (a)

State	Conflict with Cost-of-Service	Undermines Economic Efficiency	Subsidies to High-Cost Customers	Distorts Price Signals	Discourages Efficient Water Use	Encourages Growth in High-Cost Areas	Encourages Overinvestment	Fails to Account for Contributions	Unnecessary Incentives	Inappropriate Without Interconnection	Not Acceptable to All Customers	Not Acceptable to Agencies	Not Justified in a Specific Case	Insufficient Precedents	Overall Costs Outweigh Benefits	Other	Number of "Yes" Responses
Nebraska	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nevada	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
New Hampshire	Yes	No	Yes	No	No	No	No	Yes	No	Yes	Yes	No	No	No	No	No	5
New Jersey	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	0
New Mexico	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
New York	Yes	Yes	Yes	Yes	Yes	No	No	Yes	No	Yes	Yes	No	Yes	No	No	No	9
North Carolina	Yes	No	Yes	Yes	No	No	No	No	No	No	No	No	No	No	No	No	3
North Dakota	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Ohio	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	0
Oklahoma	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Oregon	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	0
Pennsylvania	Yes	No	Yes	No	No	No	No	No	No	No	Yes	No	No	No	No	No	3
Rhode Island	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
South Carolina	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	0
South Dakota	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ
Tennessee	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Texas	No	No	Yes	No	No	No	No	No	No	No	Yes	No	No	No	No	No	2
Utah	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Vermont	No	No	Yes	Yes	No	No	No	No	No	Yes	Yes	No	No	No	No	No	4
Virginia	Yes	No	Yes	No	No	No	No	No	Yes	No	No	No	No	No	No	No	3
Washington	No	No	No	Yes	Yes	No	No	No	No	No	Yes	No	No	No	No	No	3
West Virginia	Yes	No	No	No	No	No	No	Yes	No	No	No	No	Yes	No	No	No	3
Wisconsin	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI	NI
Wyoming	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
D.C.	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ	NJ

NA = Not applicable; NR = Not reported; NJ = No jurisdiction

TABLE E4
Arguments Against Single-Tariff Pricing (a)

State	Conflict with Cost-of-Service	Undermines Economic Efficiency	Subsidies to High-Cost Customers	Distorts Price Signals	Discourages Efficient Water Use	Encourages Growth in High-Cost Areas	Encourages Overinvestment	Fails to Account for Contributions	Unnecessary Incentives	Inappropriate Without Interconnection	Not Acceptable to All Customers	Not Acceptable to Agencies	Not Justified in a Specific Case	Insufficient Precedents	Overall Costs Outweigh Benefits	Other	Number of "Yes" Responses
Summary Data																	
Yes	14	3	12	7	4	4	1	6	2	8	10	2	6	2	2	0	--
No	7	18	9	14	17	17	20	15	19	13	11	19	15	19	19	21	--
Not an issue	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	--
Not applciable	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	--
No jurisidction	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	--
Total	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	--

(a) These findings reflect staff views about the arguments affecting commission deliberations or policies.

NA = Not applicable; NR = Not reported; NJ = No jurisdiction

Rate Design Surrebuttal Testimony of Jodi A. Jerich
Arizona Water Company
Docket N. W-01445A-08-0440

EXHIBIT B

Exhibit B

	"A" Maintain Separate Systems	"B" Company Proposed Consolidation	"C" Full Consolidation by Group	"D" Full Consolidation of all 17 Districts	"E" Fully Consolidated Base Rates and Separate Commodity Rates	"F" Modified Option E w/ Adjusted Base Rate to Minimize Rates
EASTERN GROUP						
5/8" x 3/4" Metered Customers / Avg. gallons						
Superstition *18,257 / 7,358*	$0.12 0.36%	$2.24 6.63%	$3.16 9.36%	**($0.75)** **(2.22%)**	**($0.05)** **(0.15%)**	$0.02 0.05%
Bisbee *3,085 / 5,215*	$3.86 12.93%	$2.20 7.36%	$2.08 6.96%	**($1.30)** **(4.36%)**	$4.04 13.52%	$4.25 14.23%
Sierra Vista *2,664 / 8,924*	**($3.35)** **(11.24%)**	**($1.33)** **(4.47%)**	$10.71 35.96%	$6.42 21.56%	**($2.88)** **(9.68%)**	**($2.37)** **(7.94%)**
San Manuel *1,477 / 8,745*	$3.99 9.13%	$3.99 9.13%	**($3.66)** **(8.38%)**	**($7.91)** **(18.08%)**	$3.57 8.15%	$4.34 9.91%
Oracle *1,389 / 5,605*	**($2.89)** **(6.12%)**	**($2.89)** **(6.12%)**	**($14.42)** **(30.53%)**	**($17.90)** **(37.88%)**	**($4.30)** **(9.11%)**	**($3.64)** **(7.70%)**
Winkelman *144 / 9,459*	$6.38 26.94%	$6.38 26.94%	$18.04 76.12%	$13.62 57.47%	$6.28 26.48%	$5.00 21.10%
Miami *2,820 / 5,995*	$13.89 40.55%	**($2.21)** **(6.44%)**	**($0.54)** **(1.57%)**	**($4.11)** **(11.99%)**	$13.68 39.93%	$5.00 14.59%
Reductions: Group Ratio	2 : 7	3 : 7	3 : 7	5 : 7	3 : 7	2 : 7
Largest $ Reduction vs. Largest $ Increase in group	($3.35)/(11.24%) Sierra Vista vs. $13.89/40.55% Miami	($2.89)/(6.12%) Oracle vs. $6.38/26.94% Winkelman	($14.42)/(30.53%) Oracle vs. $18.04/76.12% Winkelman	($17.90)/(37.88%) Oracle vs. $13.62/57.47% Winkelman	($4.30)/(9.11%) Oracle vs. $13.68/39.93% Miami	($3.64)/(7.70%) Oracle vs. $5.00/21.10% Winkelman

	"A" Maintain Separate Systems	"B" Company Proposed Consolidation	"C" Full Consolidation by Group	"D" Full Consolidation of all 17 Districts	"E" Fully Consolidated Base Rates and Separate Commodity Rates	"F" Modified Option E w/ Adjusted Base Rate to Minimize Rates
WESTERN GROUP						
5/8' x 3/4" Metered Customers / Avg. gallons						
Casa Grande *20,642 / 8,843*	$3.58 13.48%	$3.30 12.42%	$4.36 16.42%	$9.51 35.86%	$3.09 11.66%	$3.06 11.55%
Stanfield *179 / 9,162*	$43.53 102.19%	**($7.37)** **(17.30%)**	**($11.15)** **(26.17%)**	**($5.90)** **(13.84%)**	$43.89 103.04%	$5.00 11.74%
White Tank *1,573 / 15,648*	$1.67 2.74%	$1.67 2.74%	**($15.36)** **(25.27%)**	($7.78) (12.79%)	$1.56 2.57%	$1.38 2.27%
Ajo *604 / 5,185*	$3.41 7.33%	$3.41 7.33%	**($22.15)** **(47.58%)**	**($18.07)** **(38.82%)**	$0.75 1.62%	$1.87 4.02%
Coolidge *4,229 / 8,134*	**($0.78)** **(3.03%)**	$2.55 9.96%	$4.02 15.68%	$8.96 35.00%	**($0.78)** **(3.03%)**	**($0.42)** **(1.65%)**
Reductions: Group Ratio	1 : 5	1 : 5	3 : 5	2 : 5	1 : 5	1 : 5
Largest $ Reduction vs. Largest $ Increase in group	($0.78)/(3.03%) Coolidge vs. $43.53/102.91% Stanfield	($7.37)/(17.30%) Stanfield v. $3.41/7.33% Ajo	($22.15)/(47.58%) Ajo vs. $4.36/16.42% Casa Grande	($18.07)/(38.82%) Ajo vs. $9.51/35.86% Casa Grande	($0.78)/(3.03%) Coolidge vs. $43.89/103.04% Stanfield	($0.42)/(1.65%) Coolidge vs. $5.00/11.74% Stanfield

Exhibit B

	"A" Maintain Separate Systems	"B" Company Proposed Consolidation	"C" Full Consolidation by Group	"D" Full Consolidation of all 17 Districts	"E" Fully Consolidated Base Rates and Separate Commodity Rates	"F" Modified Option E w/ Adjusted Base Rate to Minimize Rates
NORTHERN GROUP						
5/8" x 3/4" metered Customers / Avg. gallons						
Lakeside *4,679 / 4,312*	**($5.02) (13.80%)**	**($5.27) (14.51%)**	**($7.36) (20.24%)**	**($9.67) (26.61%)**	**($5.14) (14.15%)**	**($5.21) (14.33%)**
Overgaard *4,110 / 2,765*	**($7.41) (24.15%)**	**($7.08) (23.05%)**	**($5.08) (16.54%)**	**($7.12) (23.20%)**	**($7.59) (24.73%)**	**($7.18) (23.38%)**
Sedona *5,154 / 10,264*	$0.84 2.30%	$2.33 6.40%	$6.08 16.70%	$2.69 7.38%	**($0.23) (0.63%)**	**($0.30) (0.83%)**
Pinewood *2,862 / 2,407*	**($1.93) (6.71%)**	**($1.79) (6.22%)**	**($3.76) (13.08%)**	**($5.75) (20.02%)**	$3.96 13.77%	**($3.24) (11.27%)**
Rimrock *1,230 / 6,165*	$5.36 11.54%	**($5.59) (12.04%)**	**($13.24) (28.54%)**	**($15.89) (34.25%)**	$5.14 11.08%	$5.00 10.78%
Reductions: Group Ratio	3 : 5	4 : 5	4 : 5	4 : 5	3 : 5	4 : 5
Largest $ Reduction vs. Largest $ Increase in group	($7.41)/(24.15%) Overgaard vs. $5.36/11.54% Rimrock	($7.08)/(23.05%) Overgaard vs. $2.33/6.40% Sedona	($13.24)/(28.54%) Rimrock vs. $6.08/16.70% Sedona	($15.89)/(34.25%) Rimrock vs. $2.69/7.38% Sedona	($7.59)/(24.73%) Overgaard vs. $5.14/11.08% Rimrock	($7.18)/(23.38%) Overgaard vs. $5.00/10.78% Rimrock

Exhibit B

ANALYSIS OF ALL 17 DISTRICTS

	"A" Maintain Separate Systems	"B" Company Proposed Consolidation	"C" Full consolidation by Group	"D" Full Consolidation of all 17 Districts	"E" Fully Consolidated Base Rates and Separate Commodity Rates	"F" Modified Option E w/ Adjusted Base Rate to Minimize Rates
TOTAL						
Reductions: Districts Ratio	6 : 17	8 : 17	9 : 17	11 : 17	7 : 17	7 : 17
Largest $ Reduction vs. Largest $ Increase in all districts	($7.41)/(24.15%) Overgaard vs. $43.53/102.91% Stanfield	($7.37)/(17.30%) Stanfield vs. $6.38/26.94% Winkelman	($22.15)/(47.58%) Ajo vs. $18.04/76.12% Winkelman	($18.07)/(38.82%) Ajo vs. $13.62/57.47% Winkelman	($7.59)/(24.73%) Overgaard vs. $43.89/103.04% Stanfield	($7.18)/(23.38%) Overgaard Vs. $5.00/21.10% Winkelman

Exhibit B

Exhibit B

	"A" Maintain Separate Systems	"B" Company Proposed Consolidation	"C" Full Consolidation by Group	"D" Full Consolidation of all 17 Districts	"E" Fully Consolidated Base Rates and Separate Commodity Rates	"F" Modified Option E w/ Adjusted Base Rate to Minimize Rates
From largest $ reduction to $ largest increase Rate Decrease Up to $5.00 [redacted] [redacted] [redacted]	1. ($7.41)/(24.15%) Overgaard 2. ($5.02)/(13.80%) Lakeside 3. ($3.35)/(11.24%) Sierra Vista 4. ($2.89)/(6.12%) Oracle 5. ($1.93)/(6.71%) Pinewood 6. ($0.78)/3.03%) Coolidge 7. $0.12/0.36% Superstition 8. $0.84/2.30% Sedona 9. $1.67/2.74% White Tank 10. $3.41/7.33% Ajo 11. $3.58/13.48% Casa Grande 12. $3.86/12.93% Bisbee 13. $3.99/9.13% San Manuel [redacted]	1. ($7.37)/(17.30%) Stanfield 2. ($7.08)(23.05%) Overgaard 3. ($5.59)/(12.04%) Rimrock 4. ($5.27)/(14.51%) Lakeside 5. ($2.89)/(6.12%) Oracle 6. ($2.21)/(6.44%) Miami 7. ($1.79)/(6.22%) Pinewood 8. ($1.33)/(4.47%) Sierra Vista 9. $1.67/2.74% White Tank 10. $2.20/7.36% Bisbee 11. $2.24/6.63% Superstition 12. $2.33/6.40% Sedona 13. $2.55/9.96% Coolidge 14. $3.30/12.42% Casa Grande 15. $3.41/7.33% Ajo 16. $3.99/9.13% San Manuel [redacted]	1. ($22.15)/(47.58%) Ajo 2. ($15.36)/(25.27%) White Tank 3. ($14.42)/(30.53%) Oracle 4. ($13.24)/(28.54%) Rimrock 5. ($11.15)/(26.17%) Stanfield 6. ($7.36)/20.24%) Lakeside 7. ($5.08)/(16.54%) Overgaard 8. ($3.76)/(13.08%) Pinewood 9. ($3.66)/(8.38%) San Manuel 10. ($0.54)/(1.57%) Miami 11. $2.08/6.96% Bisbee 12. $3.16/9.36% Superstition 13. $4.02/15.68% Coolidge [redacted]	1. ($18.07)/(38.82%) Ajo 2. ($17.90)/(37.88%) Oracle 3. ($15.89)/(34.25%) Rimrock 4. ($9.67)/(26.61%) Lakeside 5. ($7.91)/(18.08%) San Manuel 6. ($7.78)/(12.79%) White Tank 7. ($7.12)/(23.20%) Overgaard 8. ($5.90)/(13.84%) Stanfield 9. ($5.75)/(20.02%) Pinewood 10. ($4.11)/(11.99%) Miami 11. ($1.30)/(4.36%) Bisbee 11. ($0.75)/(2.22%) Superstition 13. $2.69/7.38% Sedona [redacted]	1. ($7.59)/(24.73%) Overgaard 2. ($5.14)/(14.15%) Lakeside 3. ($4.30)/(9.11%) Oracle 4. ($2.88)/(9.68%) Sierra Vista 5. ($0.78)/(3.03%) Coolidge 6. ($0.23)/(0.63%) Sedona 7. ($0.05)/(0.15%) Superstition 8. $0.75/1.62% Ajo 9. $1.56/2/57% White Tank 10. $3.09/11.66% Casa Grande 11. $3.57/8.15% San Manuel 12. $3.96/13.77% Pinewood 13. $4.40/13.52% Bisbee [redacted]	1. ($7.18)/(23.38%) Overgaard 2. ($5.21)/(14.33%) Lakeside 3. ($3.64)/(7.70%) Oracle 4. ($3.24)/(11.27%) Pinewood 5. ($2.37)/(7.94%) Sierra Vista 6. ($0.42)/(1.65%) Coolidge 7. $0.02/0.05% Superstition 8. $0.30/0.83% Sedona 9. $1.38/2.27% White Tank 10. $1.87/4.02% Ajo 11. $3.06/11.55% Casa Grande 12. $4.25/14.23% Bisbee 13. $4.34/9.91% San Manuel 14. $5.00/10.78% Rimrock 15. $5.00/11.74% Stanfield 16. $5.00/14.59% Miami 17. $5.00/21.10% Winkelman

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
CHAIRMAN
GARY PIERCE
COMMISSIONER
SANDRA D. KENNEDY
COMMISSIONER
PAUL NEWMAN
COMMISSIONER
BOB STUMP
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY, AND FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR CERTAIN RELATED APPROVALS BASED THEREON.	Docket No. W-01445A-08-0440

NOTICE OF ERRATA

The Residential Utility Consumer Office ("RUCO") hereby files this Notice of Errata in connection with the Surrebuttal Rate Design Testimony of Jodi A. Jerich, which was filed August 12, 2009, in the above-referenced matter. In its original submission, RUCO intended to evaluate all consolidation models by the recommended revenue requirement from Surrebuttal Testimony. In error, some of the models were based on recommendations made in Direct Testimony. This submission has been corrected to reflect RUCO's original intent.

Please see the attached revised pages 11 – 24 of Ms. Jerich's Testimony, and Revised Exhibit B 8/28/09.

EXHIBIT
R-36
ADMITTED

RESPECTFULLY SUBMITTED this 28th day of August, 2009.

Michelle L. Wood
Counsel

An Original and Thirteen (13) Copies of the foregoing were filed this 28th day of August, 2009 with:

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Phoenix, Arizona 85007

COPIES of the foregoing hand delivered/ mailed this 28th day of August, 2009 to:

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By Ernestine Gamble
Ernestine Gamble

utilities have either outstanding NOVs and have recently resolved an NOV: Winchester Heights (129 customers), Monte Vista (40 customers), Sonoita Valley (40 customers), and Ashcreek (91 customers and currently operated by an interim manager).

Q. What are the arguments in opposition to rate consolidation?

A. The EPA-NARUC publication also offers several arguments in opposition to rate consolidation. RUCO lists the arguments it finds most persuasive.

1. Conflicts with cost of service principles.
2. Provides subsidies to some high cost customers at the expense of other customers.
3. Distorts price signals.
4. Discourages water conservation.

Q. Are these important considerations for RUCO?

A. Absolutely. All four of these arguments are strong reasons to reject a proposal to consolidate rates. However, RUCO contends that it has identified a rate consolidation design (Option F) that mitigates these concerns to some degree.

Q. Explain the rate design options considered by RUCO.

A. RUCO identified six (6) rate design options using the revenue requirements it filed in its surrebuttal testimony. I have attached these options as ~~Exhibit B~~ **REVISED Exhibit B 8/28/09**.

RUCO decided not to limit its consideration of rate consolidation solely to the proposal submitted by the Company. Instead, RUCO reviewed several different rate consolidation options. By reviewing ~~Exhibit B~~ **REVISED Exhibit B 8/28/09**, it will be readily apparent why RUCO prefers Option F over other rate consolidation proposals.

Q. Before going into detail for all the rate consolidation options, please explain Option F and why RUCO prefers Option F.

A. Option F ensures that no system receives more than a $5.00 increase for its average residential ratepayer. This Option consolidates all 17 systems into a single base rate. However, each system retains its own individual commodity rates. No system would incur more than a $5.00/month increase in rates for the average residential ratepayer.

There are several reasons why RUCO prefers Option F. First, this proposal consolidates <u>all</u> 17 systems into a single base rate. Instead of matching up one large system for the perpetual subsidization of a smaller system, costs are spread to all ratepayers. This is the only practical method where a large system would realize any significant financial benefit from consolidation. When consolidation is limited to pairing a large system with a small one, the larger system always subsidizes the majority of the smaller system's costs. The smaller system would only cover a minor portion of the larger system's

costs.[5] Second, under Option F, no system would realize more than a $5.00 rate increase. Under all other proposals, some systems would receive very large increases, while some others would see very large decreases. Option F has the most narrow band width between the dollar amounts for systems that get a decrease and those that receive an increase. Third, Option F retains individual system commodity rates. This requires the Company to keep track of expenses on a per system basis and allows Commission Staff a morethorough review of the Company's books. Fourth, separate commodity rates are based on cost of service. Option F preserves some integrity for this ratemaking principle. Finally, Option F's individual commodity rates mitigates the concern that rate consolidation would discourage water conservation.

Q. Please review the six (6) rate design options.

A. ***Option A*** ***<u>Maintain Separate Systems</u>***

Option A is a traditional rate design with ***no consolidation***. This option adheres to the cost of service principle and the plan encourages water conservation, but Miami and Stanfield will experience rate shock with ~~40.55%~~ **39.20%** and ~~102.19%~~ **108.35%** average increases, respectively.

[5] For illustrative purposes, System A has 90 customers and is consolidated with System B which as 10 customers. In Year 1, System B incurs $1,000 of capital costs. Under consolidation, System A picks up 90% of these costs while the System B covers only 10%. In Year 3 when System A needs $9,000 of capital improvements, System A still covers 90% of its own expenses while System B only picks up 10%. With more systems consolidated, costs are further spread and the percentage of costs subsidized is reduced.

Each system has its own base rate and commodity charges based on the cost of service for that individual system.

Option B ***<u>Company Proposed Consolidation</u>***

This is the consolidation option proposed by the Company. It consolidates some of the systems and leaves others alone. The Company proposes to consolidate several systems – typically matching a large system with a small one. Some of the consolidated systems are fully consolidated and others only have a consolidated base rate and separate commodity rates. This proposal may avoid rate shock, but the pairing of larger systems with smaller systems will result in cross subsidization of smaller systems in a way which is inequitable for the larger system. There are more equitable options to consider.

Option C ***<u>Full Consolidation by Group</u>***

The Company divides its 17 systems into three Groups: The Northern Group, the Eastern Group and the Western Group. RUCO designed rates for the consolidation of the 17 systems into three groups. All the systems in the Northern Group would be combined into one rate design and the same for the Eastern Group and the Western Group. This option does not address rate shock to Winkelman and Sierra Vista.

Option D ***Full Consolidation of all 17 Systems***

Option D consolidates all 17 systems into a single rate design. All systems would have the same base rate ***and*** the same commodity rates. This option has the same problems as Options B and C. The option does not ~~have to~~ address rate shock to Winkelman.

Option E ***Fully Consolidated Base Rate with Individual Commodity Rates***

Option E is a variation of Option D. All 17 systems would have the same base rate ***but have their own commodity rates***. Retention of commodity rates encourages water conservation, sends the appropriate price signals for proper water conservation and honors cost of service principles. However, this option does not avoid rate shock to Miami and Stanfield.

Option F ***Modified Option E with an adjusted base rate to ensure no system incurs more than a $5.00 increase.***

Option F is Option E with one modification to address issues of rate shock and provides greater rate stability. The modification in Option F reduces the revenue requirement for those systems that would have experienced an increase larger than $5.00 under Option E by adjusting the base rate for all systems. By doing so, no system has more than a $5.00 increase for the average residential customer. This also has the effect of diminishing the reductions some systems would have experienced under Option E. In effect,

it narrows the band of change from the present rates and provides additional support for the argument that rate consolidation provides rate stability.

Q. Why doesn't RUCO support the rate consolidation plan proposed by the Company (Option B)?

A. The Company's proposal results in inequitable unilateral subsidization of smaller systems by larger systems. RUCO finds that this type of rate consolidation is a one way street always benefitting one system and always burdening the other system.

As in the past, the Company's current proposal matches a large system with one or two small systems.[6] The purpose of this type of consolidation is to mitigate the rate increase of the smaller system by having the larger system pay more than its fair share.

One of the reasons FULL rate consolidation appeals to RUCO in this docket is that it allows everyone's costs to be spread across all the systems. While consolidation in this rate case will initially have some systems pay some costs for other systems, over time those systems that pick up some costs from other systems will receive relief in the future when other systems pick up some of their costs. In the Company's proposal, there is no way that the small

[6] The Company matches Superstition (18,257 customers) with Miami (2,820 customers) and Casa Grande (20,642 customers) with Stanfield (179) and Coolidge (4,229). Sedona (5,154) will subsidize Pinewood (2,862) and Rimrock (1,230). The Company does propose to consolidate the two similarly sized systems of Bisbee (3,085) and Sierra Vista (2,664).

systems will provide any meaningful rate benefit for their larger "host" system in the future. The larger system will always be covering for the smaller system. This perpetual inequity requires RUCO to oppose the Company's limited rate consolidation proposal.

For example (as shown in ~~Exhibit B~~ **REVISED Exhibit B 8/28/09**), under the traditional cost of service rate design of Option A (no consolidation), the Miami system is to receive a ~~$13.89 (40.55%)~~ **$13.43 (39.20%) *increase*** to cover its expenses. However, under the Company's proposal to consolidate Miami with Superstition as shown in Option B, Miami would enjoy a ~~$2.21 (6.44%)~~ **$2.53 (7.39%) *decrease***. This cost shift goes too far. It's one consideration if the purpose of rate consolidation is to ***mitigate*** rate increases for smaller systems. It's another concern entirely to ***eliminate*** any responsibility for that system to cover its own costs. Meanwhile, Superstition's rate ~~increase~~ jumps from ~~$0.12 (0.36%)~~ **a $0.30 (0.90%) *decrease*** without consolidation to ~~$2.24 (6.63%)~~ **a $1.84 (5.45%) *increase*** under the Company's proposed consolidation plan. Miami's 2,820 customers will always benefit from merging rates with Superstition's 18,257 customers. And Superstition would never benefit in any meaningful way from this plan in the future because Miami is simply too small to absorb any substantial portion of Superstition's costs.

The Company also proposes to consolidate Casa Grande (29,642), Coolidge (4,229) and Stanfield (179). Without rate consolidation, Stanfield ratepayers

would be hit with a ~~$43.53 (102.19%)~~ ***$46.15 (108.35%) increase***. The Company's consolidation proposal does far more than merely mitigate this increase. Under the Company's proposal, Stanfield would see a ~~$7.37 (17.30%)~~ **$6.21 (14.58%)** ***decrease***. These costs would be picked up primarily by Coolidge, which would see its ~~$0.78 (3.03%)~~ **$0.84 (3.29%)** rate ***decrease*** turn into a ~~$2.55 (9.96%)~~ **$2.51 (9.80%)** rate ***increase***. Finally, the Sedona/Rimrock/Pinewood proposal would see Rimrock swing from a ~~$5.36 (11.54%)~~ **$5.83 (12.55%)** ***increase*** to a ~~$5.59 (12.04%)~~ **$4.97 (10.71%)** ***decrease***. Again, rate consolidation should not eliminate all cost recovery obligations for a system.

Q. What are some of the considerations of Option C, which consolidates the 17 systems into 3 consolidated rates groups?

A. There are two primary considerations for rate consolidation by Group. First, the consolidated systems are geographically close. From past Commission decisions, geographic proximity has, at times, been a factor weighing in favor of consolidation. Furthermore, Company resources such as employees, maintenance equipment, fleet vehicles and office space are shared by these systems. Second, a future rate case would not require the Company to file an application on a company-wide basis. As in the past, the Company could come in for a rate application for a single consolidated Group. This may be less of a strain on resources for both the Company and Staff compared to a company-wide rate case. Nonetheless, RUCO finds Option F a better rate design than Option C in this case because it spreads the costs to all the

ratepayers company-wide and it mitigates the impact of rate increases, encourages conservation and adheres, in part, to the cost of service principle.

Q. What are some of the considerations of full rate consolidation of all 17 systems (Option D)?

A. Full rate consolidation for the entire company allows costs to be spread over a larger base of customers. This minimizes the rate impact for those customers who would have to bear the entire cost of expenses attributed to their system.

Furthermore, full rate consolidation eliminates the need to identify revenue requirements for each system. This results in administrative efficiency. As the Massachusetts Department of Public Utilities stated, "The Department has found that single tariff pricing provides benefits to customers associated with operational and functional consolidation. In addition, single tariff pricing is consistent with the goal of administrative simplicity." (DPU 86-27-A at 77-85; DPU 17885, at 5.).

In order to consolidate all systems, some customers will pay more and some will pay less. However, systems that picked up other systems' costs will receive a benefit from those other systems in the future because their costs will be spread across other systems.

since the widespread sharing of these costs minimizes the rate increase. This may incent a Company to unnecessarily inflate its rate base.

> "If rates were to be consolidated, there would be no reason to maintain separate books and records for each of the [systems]...However, this loss of operation and financial data would destroy the ability to evaluate the effectiveness and efficiency of the Company's operation of the [systems]. As a result, the [public utility commission] would lose its ability to exercise regulatory oversight and control as it pertains to these systems."[8]

If the Commission were to find that full rate consolidation is in the public interest, it could still order the Company to maintain system-specific bookkeeping. This would be helpful for Staff, RUCO and others to determine if costs were appropriately and prudently incurred in future rate cases.

A second concern of full rate consolidation is that this option can send improper price signals to certain systems. Rate consolidation is arguably "at odds with water conservation."[9] Water is not the same everywhere in the state. Different systems have different challenges with water quality or water quantity issues. For example, under the full rate consolidation of Option D, the Pinewood system would realize a ~~20.02%~~ **18.43%** ***decrease*** in rates. Yet, this system, like some others, has water delivery difficulties at times due to

[8] Id. at 8 citing Ernest Harwig, Direct Testimony before the New Hampshire Public Utilities Commission in DR 97-058, Pennichuck Water Works, Inc. (1997).
[9] Id. at 5.

inadequate water supplies. Full rate consolidation ignores the harsh reality of the difficulty of delivery of adequate and safe water in certain areas in Arizona.

These two concerns are important reasons why RUCO believes that the consolidation proposal in Option F is the preferred rate consolidation plan. Since Option F retains individual system commodity charges, the Company must continue to maintain books for each individual system. Second, the individual commodity rates maintain the integrity of price signals for proper water conservation. In addition to these primary concerns, Option D also does not address the rate shock to Winkelman.

Q. Discuss Option E.

A. Option E provides a single base rate for all 17 systems, but each system has its own commodity rates based on its cost of service.

As in Option D, for future rate cases, the Company would have to come in on a company-wide basis. Since each system has its own commodity rates, the Company and Staff will still have to identify a revenue requirement for each system. However, this option recognizes the importance of each system having its unique water acquisition needs. It is more challenging to deliver

water to customers in Pinewood than it is in Casa Grande. Some systems require more wells or deeper wells for the same output. In addition to water ***delivery and quantity*** issues, systems may have water ***quality*** issues that other systems do not experience. System specific commodity rates help send appropriate price signals to customers that water delivery in certain areas is more difficult than in other areas. This option also preserves some notion of cost of service on a system–by-system basis.

Q. Explain Option F and why it is RUCO's preferred consolidated rate design.

A. Should the Commission decide that consolidation in this case is in the public interest, adoption of Option F is RUCO's preferred plan for rate consolidation. It is a modified version of Option E, and its purpose was to limit the amount of the rate increase to no more than $5.00 and to narrow the band between the systems with decreased rates for the average residential user and the systems with increased rates for the average residential user.

There are several reasons why RUCO encourages the Commission to adopt the rate consolidation plan of Option F if it does decide to consolidate rates in this docket.

First, Option F was intentionally designed so that no system would experience more than a $5.00 rate increase for the average residential user. This Option avoids rate shock better than any of the other proposals.

> "A leading argument for single-tariff pricing made by multi-system water utilities is that each individual system eventually will require an infusion of capital for renovations and improvements; only the timing varies. Equalizing rates smoothes the effect of discrete cost spikes across systems and over time, much like insurance pooling."[7]

In RUCO's opinion, a favorable rate consolidation proposal is one that has the least detrimental effect to the systems that are picking up costs for other systems at the initial stage of consolidation. Over time, rates are stabilized and increases are minimized by spreading the costs over all systems.

However, the most obvious cost shift happens in the initial rate case when rate design shifts from cost of service to consolidated rates. Any effort to mitigate the impact of that shift is in the public interest. As stated earlier, Option F has the smallest dollar amount variation between those systems that receive a rate increase (no more than $5.00) and those that receive a rate decrease (no more than $7.18). Under Option D's full consolidation, the swing goes from a rate ***increase*** of ~~$13.62~~ **$15.63** to a rate ***decrease*** of ~~$18.07~~ **$17.19**.

Q. What are some concerns RUCO has with full rate consolidation (Option D)?

A. RUCO has two primary concerns. First, full rate consolidation eliminates the need to maintain books for individual systems. This could lead to the Company over-building a system or not maintaining prudent costs controls

[7] Id. at 4.

Second, Option F consolidates all base rates but maintains separate commodity rates. Those who, like RUCO, are uncomfortable with completely leaving traditional cost of service principles will take some comfort that these principles are preserved through the commodity rates.

Third, separate commodity rates also send the proper price signals for water conservation.

Fourth, Option F would require the Company to maintain separate books for each system to ensure that Staff, RUCO and others can review whether the Company is prudently incurring costs.

Q. Does this conclude your testimony?

A. Yes.

(REVISED) Exhibit B 8/28/09

	"A" Maintain Separate Systems	"B" Company Proposed Consolidation	"C" Full Consolidation by Group	"D" Full Consolidation of all 17 Districts	"E" Fully Consolidated Base Rates and Separate Commodity Rates	"F" Modified Option E w/ Adjusted Base Rate to Minimize Rates
EASTERN GROUP						
5/8" x 3/4" Metered Customers / Avg. gallons						
Superstition *18,257 / 7,358*	**($0.30)** **(0.90%)**	$1.84 5.45%	$3.03 8.99%	**($0.92)** **(2.72%)**	**($0.53)** **(1.56%)**	$0.02 0.05%
Bisbee *3,085 / 5,215*	$3.63 12.17%	$1.98 6.64%	$2.35 7.89%	**($1.08)** **(3.63%)**	$3.81 12.76%	$4.25 14.23%
Sierra Vista *2,664 / 8,924*	**($3.23)** **(10.84%)**	**($1.23)** **(4.12%)**	$11.40 38.27%	$7.05 23.67%	**($2.78)** **(9.32%)**	**($2.37)** **(7.94%)**
San Manuel *1,477 / 8,745*	$4.34 9.91%	$4.34 9.91%	**($1.75)** **(4.00%)**	**($6.93)** **(15.84%)**	$3.98 9.10%	$4.34 9.91%
Oracle *1,389 / 5,605*	**($2.61)** **(5.53%)**	**($2.61)** **(5.53%)**	**($13.66)** **(28.91%)**	**($17.19)** **(36.37%)**	**($4.05)** **(8.57%)**	**($3.64)** **(7.70%)**
Winkelman *144 / 9,459*	$7.30 30.82%	$7.30 30.82%	$20.18 85.14%	$15.63 65.95%	$7.07 29.82%	$5.00 21.10%
Miami *2,820 / 5,995*	$13.43 39.20%	**($2.53)** **(7.39%)**	**($0.73)** **(2.13%)**	**($4.36)** **(12.73%)**	$12.98 37.87%	$5.00 14.59%
Reductions: Group Ratio	3 : 7	3 : 7	3 : 7	5 : 7	3 : 7	2 : 7
Largest $ Reduction vs. Largest $ Increase in group	($3.23)/(10.84%) Sierra Vista vs. $13.43/39.20% Miami	($2.61)/(5.53%) Oracle vs. $7.30/30.82% Winkelman	($13.66)/(28.91%) Oracle vs. $20.18/85.14% Winkelman	($17.19)/(36.37%) Oracle vs. $15.63/65.95% Winkelman	($4.05)/(8.57%) Oracle vs. $12.98/37.87% Miami	($3.64)/(7.70%) Oracle vs. $5.00/21.10% Winkelman

	"A" Maintain Separate Systems	"B" Company Proposed Consolidation	"C" Full Consolidation by Group	"D" Full Consolidation of all 17 Districts	"E" Fully Consolidated Base Rates and Separate Commodity Rates	"F" Modified Option E w/ Adjusted Base Rate to Minimize Rates
WESTERN GROUP						
5/8' x 3/4" Metered Customers / Avg. gallons						
Casa Grande *20,642 / 8,843*	$2.78 10.38%	$2.76 10.41%	$4.06 15.15%	$9.28 34.65%	$2.48 9.24%	$3.06 11.55%
Stanfield *179 / 9,162*	$46.15 108.35%	**($6.21)** **(14.58%)**	**($7.91)** **(18.57%)**	**($2.56)** **(6.00%)**	$46.53 109.24%	$5.00 11.74%
White Tank *1,573 / 15,648*	$1.11 1.82%	$1.10 1.80%	**($15.71)** **(25.83%)**	**($8.07)** **(13.28%)**	$0.93 1.52%	$1.38 2.27%
Ajo *604 / 5,185*	$4.21 9.05%	$4.21 9.05%	**($20.94)** **(44.98%)**	**($16.80)** **(36.09%)**	$1.46 3.14%	$1.87 4.02%
Coolidge *4,229 / 8,134*	**($0.84)** **(3.29%)**	$2.51 9.80%	$4.50 17.57%	$9.54 37.23%	**($0.82)** **(3.19%)**	**($0.42)** **(1.65%)**
Reductions: Group Ratio	1 : 5	1 : 5	3 : 5	3 : 5	1 : 5	1 : 5
Largest $ Reduction vs. Largest $ Increase in group	($0.84)/(3.29%) Coolidge vs. $46.15/108.35% Stanfield	($6.21)/(14.58%) Stanfield v. $4.21/9.05% Ajo	($20.94)/(44.98%) Ajo vs. $4.50/17.57% Coolidge	($16.80)/(36.09%) Ajo vs. $9.54/37.23% Coolidge	($0.82)/(3.19%) Coolidge vs. $46.53/109.24% Stanfield	($0.42)/(1.65%) Coolidge vs. $5.00/11.74% Stanfield

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	"A" Maintain Separate Systems	"B" Company Proposed Consolidation	"C" Full Consolidation by Group	"D" Full Consolidation of all 17 Districts	"E" Fully Consolidated Base Rates and Separate Commodity Rates	"F" Modified Option E w/ Adjusted Base Rate to Minimize Rates
NORTHERN GROUP						
5/8" x 3/4" metered Customers / Avg. gallons						
Lakeside *4,679 / 4,312*	**($5.53)** **(15.20%)**	**($5.78)** **(15.89%)**	**($7.43)** **(20.45%)**	**($9.77)** **(26.89%)**	**($5.46)** **(15.01%)**	**($5.21)** **(14.33%)**
Overgaard *4,110 / 2,765*	**($7.39)** **(24.07%)**	**($7.06)** **(22.99%)**	**($4.80)** **(15.63%)**	**($6.86)** **(22.34%)**	**($7.53)** **(24.51%)**	**($7.18)** **(23.38%)**
Sedona *5,154 / 10,264*	$0.30 0.82%	$1.77 4.86%	$6.27 17.20%	$2.81 7.72%	**($0.71)** **(1.96%)**	**($0.30)** **(0.83%)**
Pinewood *2,862 / 2,407*	**($1.52)** **(5.27%)**	**($1.37)** **(4.78%)**	**($3.30)** **(11.48%)**	**($5.30)** **(18.43%)**	**($3.65)** **(12.70%)**	**($3.24)** **(11.27%)**
Rimrock *1,230 / 6,165*	$5.83 12.55%	**($4.97)** **(10.71%)**	**($12.62)** **(27.20%)**	**($15.28)** **(32.93%)**	$5.60 12.07%	$5.00 10.78%
Reductions: Group Ratio	3 : 5	4 : 5	4 : 5	4 : 5	4 : 5	4 : 5
Largest $ Reduction vs. Largest $ Increase in group	($7.39)/(24.07%) Overgaard vs. $5.83/12.55% Rimrock	($7.06)/(22.99%) Overgaard vs. $1.77/4.86% Sedona	($12.62)/(27.20%) Rimrock vs. $6.27/17.20% Sedona	($15.28)/(32.93%) Rimrock vs. $2.81/7.72% Sedona	($7.53)/(24.51%) Overgaard vs. $5.60/12.07% Rimrock	($7.18)/(23.38%) Overgaard vs. $5.00/10.78% Rimrock

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ANALYSIS OF ALL 17 DISTRICTS

	"A" Maintain Separate Systems	"B" Company Proposed Consolidation	"C" Full consolidation by Group	"D" Full Consolidation of all 17 Districts	"E" Fully Consolidated Base Rates and Separate Commodity Rates	"F" Modified Option E w/ Adjusted Base Rate to Minimize Rates
TOTAL						
Reductions: Districts Ratio	7 : 17	8 : 17	10 : 17	12 : 17	8 : 17	7 : 17
Largest $ Reduction vs. Largest $ Increase in all districts	($7.39)/(24.15%) Overgaa07 vs. $46.15/108.35% Stanfield	($7.06)/(22.99%) Overgaard vs. $7.30/30.82% Winkelman	($20.94)/(44.98%) Ajo vs. $20.18/85.14% Winkelman	($17.19)/(36.37%) Oracle vs. $15.63/65.95% Winkelman	($7.53)/(24.51%) Overgaard vs. $46.53/109.24% Stanfield	($7.18)/(23.38%) Overgaard Vs. $5.00/21.10% Winkelman

(REVISED) Exhibit B 8/28/09

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	"A" Maintain Separate Systems	"B" Company Proposed Consolidation	"C" Full Consolidation by Group	"D" Full Consolidation of all 17 Districts	"E" Fully Consolidated Base Rates and Separate Commodity Rates	"F" Modified Option E w/ Adjusted Base Rate to Minimize Rates
From largest $ reduction to $ largest increase Rate Decrease Up to $5.00 $5.01 - $10.00 $10.01 - $20.00 +$20.00	1. ($7.39)/(24.07%) Overgaard 2. ($5.53)/(15.20%) Lakeside 3. ($3.23)/(10.84%) Sierra Vista 4. ($2.61)/(5.53%) Oracle 5. ($1.52)/(5.27%) Pinewood 6. ($0.84)/3.29%) Coolidge 7. ($0.30)/(0.90%) Superstition 8. $0.30/0.82% Sedona 9. $1.11/1.82% White Tank 10. $2.78/10.38% Casa Grande 11. $3.63/12.17% Bisbee 12. $4.21/9.05% Ajo 13. $4.34/9.91% San Manuel 14. $5.83/12.55% Rimrock 15. $7.30/30.82% Winkelman 16. $13.43/39.20% Miami 17. $46.15/108.35% Stanfield	1. ($7.06)(22.99%) Overgaard 2. ($6.21)/(14.58%) Stanfield 3. ($5.78)/(15.89%) Lakeside 4. ($4.97)/(10.71%) Rimrock 5. ($2.61)/(5.53%) Oracle 6. ($2.53)/(7.39%) Miami 7. ($1.37)/(4.78%) Pinewood 8. ($1.23)/(4.12%) Sierra Vista 9. $1.10/1.80% White Tank 10. $1.77/4.86% Sedona 11. $1.84/5.45% Superstition 12. $1.98/6.64% Bisbee 13. $2.51/9.80% Coolidge 14. $2.76/10.41% Casa Grande 15. $4.21/9.05% Ajo 16. $4.34/9.91% San Manuel 17. $7.30/30.82% Winkelman	1. ($20.94)/(44.98%) Ajo 2. ($15.71)/(25.83%) White Tank 3. ($13.66)/(28.91%) Oracle 4. ($12.62)/(27.20%) Rimrock 5. ($7.91)/(18.57%) Stanfield 6. ($7.43)/20.45%) Lakeside 7. ($4.80)/(15.63%) Overgaard 8. ($3.30)/(11.48%) Pinewood 9. ($1.75)/(4.00%) San Manuel 10. ($0.73)/(2.13%) Miami 11. $2.35/7.89% Bisbee 12. $3.03/8.99% Superstition 13. $4.06/15.15% Casa Grande 14. $4.50/17.57% Coolidge 15. $6.27/17.20% Sedona 16. $11.40/38.27% Sierra Vista 17. $20.18/85.14% Winkelman	1. ($17.19)/(36.37%) Oracle 2. ($16.80)/(36.09%) Ajo 3. ($15.28)/(32.93%) Rimrock 4. ($9.77)/(26.89%) Lakeside 5. ($8.07)/(13.28%) White Tank 6. ($6.93)/(15.84%) San Manuel 7. ($6.86)/(22.34%) Overgaard 8. ($5.30)/(18.43%) Pinewood 9. ($4.36)/(12.73%) Miami 10. ($2.56)/(6.00%) Stanfield 11. ($1.08)/(3.63%) Bisbee 12. ($0.92)/(2.72%) Superstition 13. $2.81/7.72% Sedona 14. $7.05/23.67% Sierra Vista 15. $9.28/34.65% Casa Grande 16. $9.54/37.23% Coolidge 17. $15.63/65.95% Winkelman	1. ($7.53)/(24.51%) Overgaard 2. ($5.46)/(15.01%) Lakeside 3. ($4.05)/(8.57%) Oracle 4. ($3.65)/(12.70%) Pinewood 5. ($2.78)/(9.32%) Sierra Vista 6. ($0.82)/(3.19%) Coolidge 7. ($0.71)/(1.96%) Sedona 8. ($0.53)/(1.56%) Superstition 9. $0.93/1.52% White Tank 10. $1.46/3.14% Ajo 11. $2.48/9.24% Casa Grande 12. $3.81/12.76% Bisbee 13. $3.98/9.10% San Manuel 14. $5.60/12.07% Rimrock 15. $7.07/29.82% Winkelman 16. $12.98/37.87% Miami 17. $46.53/109.24% Stanfield	1. ($7.18)/(23.38%) Overgaard 2. ($5.21)/(14.33%) Lakeside 3. ($3.64)/(7.70%) Oracle 4. ($3.24)/(11.27%) Pinewood 5. ($2.37)/(7.94%) Sierra Vista 6. ($0.42)/(1.65%) Coolidge 7. ($0.30)/(0.83%) Sedona 8. $0.02/0.05% Superstition 9. $1.38/2.27% White Tank 10. $1.87/4.02% Ajo 11. $3.06/11.55% Casa Grande 12. $4.25/14.23% Bisbee 13. $4.34/9.91% San Manuel 14. $5.00/10.78% Rimrock 15. $5.00/11.74% Stanfield 16. $5.00/14.59% Miami 17. $5.00/21.10% Winkelman

DR 97-058

pennichuck water works, inc.

Petition for Permanent Rate Increase

Order Approving Settlement Agreement and Petition for Rate Consolidation

O R D E R N O. 22,883

March 25, 1998

APPEARANCES: Gallagher, Callahan and Gartrell by David A. Garfunkel, Esq. for Pennichuck Water Works, Inc.; Ransmeier and Spellman by Dom S. D'Ambruoso, Esq. for Anheuser-Busch, Inc.; Amy L. Ignatius, Esq. for the Staff of the New Hampshire Public Utilities Commission.

I. PROCEDURAL HISTORY

Pennichuck Water Works, Inc. (Pennichuck) serves the southern New Hampshire area, operating a core system that serves Nashua and portions of Amherst, Merrimack, Milford, Hollis and Bedford, as well as 10 independent community systems serving portions of Epping, Derry, Bedford, Milford and Plaistow. On May 28, 1997, Pennichuck filed with the New Hampshire Public Utilities Commission (Commission) a petition for an increase in its rates and to consolidate the rates of the core and community systems, even though the systems are not physically interconnected.

Anheuser-Busch, Inc. (AB), Pennichuck's largest customer, sought and was granted intervention.

Pennichuck requested an overall 26.98% increase in permanent rates, on a consolidated system basis. In its testimony filed July 10, 1997, Pennichuck also requested a temporary increase in revenues overall, to be derived solely from core customers, which the Commission granted by Order No. 22,683 (August 18, 1997). The 5.12% increase in revenues, on a temporary basis, excluded the community systems and all commercial and municipal fire protection customers. This resulted in a 7.8% increase in rates to those core customers affected.

Subsequent to the temporary rate order, on November 6, 1997, AB filed testimony of its expert witness, Ernest Harwig, opposing rate consolidation. Also on that date, Staff filed testimony of Douglas W. Brogan, James L. Lenihan and Mark A. Naylor. Staff witness Tracy B. Guyette filed testimony on November 13, 1997.

On December 5, 1997, AB moved for permission to file rebuttal testimony, which Staff opposed. The Commission granted the request and on December 23, 1997, AB filed rebuttal testimony of Mr. Harwig. Also on that date, Pennichuck filed rebuttal testimony of Stephen J. Densberger and its consultant Janice A. Beecher. On January 6, 1998, AB moved to strike Dr. Beecher's testimony, which Pennichuck opposed. The Commission denied the motion to strike. On January 22, 1998, AB filed surrebuttal testimony of Mr. Harwig and on the following date, Staff filed surrebuttal testimony of Mr. Brogan.

On January 30, 1998, Pennichuck and Staff submitted a Settlement Agreement on all issues except rate consolidation. The Commission took evidence on the Settlement Agreement and the contested issue of rate consolidation on February 3 through 5, 1998.

II. SETTLEMENT AGREEMENT

The Settlement Agreement addressed all issues except rate consolidation. Revenue requirements were calculated for the systems on a stand alone basis, with Pennichuck's explicit statement that it did not agree to stand alone calculations. AB did not participate in the settlement negotiations on any issue other than rate consolidation and took no position on the Settlement Agreement.

Revenue deficiency for the core was set at $511,230 and at levels for the community systems ranging from ($7,158) to $41,791, based on stipulated rate base and net operating income for the core and community systems (found as attachments to the Settlement Agreement). Pennichuck and Staff agreed on an allowed return on common equity of 10.35%, a cost of long term debt of 7.41%, cost of short term debt of 7.43%, and a treatment of a parent company infusion as short term debt, producing an overall cost of capital of 8.34%.

The proposed revenue increase would be collected on all but private and municipal fire protection customers, based on a recent review of Pennichuck's 1992 cost of service study that indicated an over-collection of fire protection charges. Pennichuck and Staff recommend, therefore, that fire protection rates remain at their present levels.

Pennichuck and Staff also agreed to a step adjustment to occur simultaneously with the increase in permanent rates, to reflect plant additions completed on or before December 31, 1997 that were made in conformance with the Safe Drinking Water Act or mandated by the City of Nashua and/or the State for highway work, or any projects in which $50,000 or more was expended on non-revenue producing items. In addition, the step adjustment would reflect one year's accumulated depreciation and related deferred

EXHIBIT R-37 ADMITTED

taxes and one year's depreciation expense and property taxes in connection with the approved plant additions. Again, private and municipal fire protection customers would be excluded from the increase.

The proposed permanent rate increase, excluding the step adjustment, is the same as that approved by the Commission for temporary rates; therefore there would be no recoupment for the difference between temporary and permanent rates. Rate case expenses, however, would be surcharged over a 12 month period. The actual amount of rate case expenses will be determined after review of a compliance filing Pennichuck is to submit upon issuance of this order.

Finally, regarding depreciation, Pennichuck and Staff agree to use the "whole life" rather than Pennichuck's proposed "average remaining life" methodology, for an annual depreciation expense of $1,272,791, which results in an annual composite depreciation rate of 2.44%.

III. POSITIONS OF THE PARTIES AND STAFF ON RATE CONSOLIDATION

A. Pennichuck and Engineering Staff

Pennichuck sought to consolidate all of the community systems into one set of rates, even though the systems are not physically interconnected. Applying the settlement figures, including the step adjustment, the consolidated rate would be approximately $253 per year for the average residential user. By contrast, again applying the settlement revenue requirements but keeping the rates on a stand alone basis would result in an average residential core rate of $245 per year; the community systems' rates would range from $291 to $1,166 per year. Single family residential customers in the core system, therefore, would pay an additional $8 per year under the rate consolidation proposal, while most of the community system customers would see a decrease in their bills.

In support of the rate consolidation proposal, Pennichuck argued that the community systems would benefit from Pennichuck's ability to upgrade or repair facilities as necessary to meet environmental mandates without fear of overwhelming community systems' customers. Because the community systems are small (ranging from 29 to 458 customers), any significant capital improvement can result in a significant increase in rates.

Pennichuck anticipates reduction in regulatory and accounting expense if the systems are consolidated, and predicts that with rate consolidation it would be better able to consider purchase of small systems in the future, as the Commission has encouraged.

Pennichuck's consultant, Janice A. Beecher, testified that commissions have ruled both ways on rate consolidation proposals, and found merit in Pennichuck's request. In her view, Pennichuck's community systems are simply too small to be viable on a stand alone basis.

Staff engineer Douglas W. Brogan testified in support of Pennichuck's proposal, concluding that the viability of the systems and their ability to come into and remain in conformance with environmental standards would be greatly enhanced by consolidation with the core. He analyzed characteristics of the systems and asserted that they bore strong similarities to the core, further bolstering the arguments for rate consolidation. He distinguished this proposal from the Consumers New Hampshire water system in which unhappiness with rate consolidation was the source of much of the impetus for the town of Hudson purchase of Consumers New Hampshire's assets. According to Brogan, the Consumers New Hampshire systems had different characteristics than the Pennichuck systems. Further, Consumers New Hampshire's service and water quality and utility management were not on a par with that of Pennichuck.

Brogan stated he would not support rate consolidation in all cases, but that the particular circumstances in this case justified approval of the request. He felt the approximately $8 per year increase to single family residential core customers under rate consolidation was justified by the benefits that accrued to all Pennichuck ratepayers, and the overall rate of $253 per year was just and reasonable.

B. Anheuser-Busch, Economics and Finance Staff

AB, Pennichuck's largest industrial customer, opposed the rate consolidation proposal. AB's consultant Ernest Harwig argued that consolidation of rates, also known as single tariff pricing (STP), was unwise regulatory policy because it breaks the connection between rates and costs. It changes the economics for water conservation, especially in the community systems, because the rate decreases produced by STP weaken the incentive to conserve. Mr. Harwig indicated that the subsidy to be paid by AB would be $20,000 annually, and he rejected the notion that Pennichuck is one large consolidated operation because of the differences between demand characteristics of the core system and those of the community systems.

Applying the Settlement revenues and assuming rate consolidation is approved, AB's yearly charge (pursuant to a special contract) would increase by $99,990, from $481,417 to $581,407. Without rate consolidation, the increase would be approximately $20,000 less, as testified by Mr. Harwig.

The Commission's Acting Finance Director, Mark A. Naylor, testified in opposition to the proposal, arguing among other things that by blending the rates there would be no tracking of the specific costs of each system. In response, Pennichuck stated that while it would not keep full books on each

system, it would record and make available all costs on a system by system basis. Naylor questioned Pennichuck's anticipated savings in regulatory and accounting costs for two reasons: 1) it could not quantify those savings and did not provide for any savings in this rate filing, and 2) its response noted above that it would track the costs of each system and this would appear to erode the anticipated savings. Mr. Naylor also testified that, unlike other regulated utilities which are moving toward deregulation as a result of alternative choices in "supplies" of product, water is unique in not enjoying such supply alternatives, and price signals to customers become even more critical in properly managing water resources.

Staff Economist James L. Lenihan also opposed consolidation on the ground that the systems are not physically interconnected and, therefore, should not have rates set on a consolidated basis. According to Lenihan, the community systems should remain on a stand alone basis in order to reflect true costs of each system. The "subsidy" by core customers, although small, would be inappropriate.

IV. COMMISSION ANALYSIS

We have reviewed the Settlement Agreement and testimony and conclude that the Settlement Agreement is a sound resolution of the rate case issues. We recognize that Pennichuck has faced extraordinary costs due to highway and other construction work mandated by the State and the City of Nashua. These capital intensive, non-revenue producing projects have put a strain on the company, in part prompting us to approve a 5.12% increase in revenues on a temporary basis in August, 1997. In addition, we recognized that the mandates of the Safe Drinking Water Act or other environmental standards have required significant investments in both the core and community systems.

Because of the magnitude of some of these investments, we will accept the recommendation that we approve a simultaneous step adjustment on the effective date of the permanent rate increase, for certain specified improvements. To do otherwise would force Pennichuck to file another rate case relatively soon, which ultimately is a cost borne by ratepayers. For projects completed in 1997 that meet the threshold criteria, we will approve the step adjustment.

While New Hampshire law is replete with references to the appropriate standard for establishing a utility's rate base and rate of return, there appears to be no specific guidance on the point of rate consolidation or single tariff pricing. Thus, in the absence of any legal impediment to utilizing single tariff pricing, our decision essentially becomes one of policy that is bound only by our statutory constraints that rates be just and reasonable and that we act in the public interest. See RSAs 374:2 and 378:28.

Opponents of rate consolidation in this case argue that we should adhere to our traditional ratemaking policy of cost causation. We find their position unpersuasive in this case for two reasons. First, traditional cost of service regulation already includes some measure of rate averaging in that customers are not charged the true costs of serving them on an individual basis. Second, and perhaps more important, stand alone rates in this case produce results for some customers that are well beyond the zone of "just and reasonable". One needs only to look at the stand alone rates that would result from the Settlement Agreement to see just how extreme the results are when significant investments are required in a very small system. Most of the community systems are simply too small to absorb the magnitude of investments mandated by environmental enactments. However, without these investments, it is clear that the small community systems would have been unable to provide safe and adequate water service to their customers.

We do not believe it would be in the public interest to impose annual rates in the range of $800 to $1200, as would be the case here, when a reasonable alternative is available. By consolidating the community systems with the core system for ratemaking purposes, all customers would face a uniform tariff which, for the average residential customer, would be approximately $253 per year. The rates for the average residential customer in the core system would increase less than $1.00 per month, for a total of $8 per year, under the rate consolidation proposal which, in light of the alternative, we find to be acceptable. We consider a single tariff rate of approximately $253 per year for the core residential customer to be just and reasonable. A consolidated rate will ensure affordability and the continued viability of many of Pennichuck's community systems. It will also enable Pennichuck to operate in a more administratively efficient manner by eliminating separate general ledgers for each system, thereby reducing administrative costs.

Although we are approving the rate consolidation proposal, we share the concerns of Mr. Naylor that there is a risk that there will be inadequate information tracked on a community system basis and, as a result, a troubled system, or over-investment, could escape the scrutiny of management and regulators. We accept the commitment of Pennichuck to record costs on a system specific basis.

We find that all investments that are the subject of this proceeding have been prudently incurred and that the facilities are used and useful in the provision of public utility service.

The result of the rate consolidation proposal and the Settlement Agreement, including the step adjustment, will be an additional increase of 12.97% for customers (excluding fire protection customers) for bills rendered on or after April 1, 1998. Together with the temporary rate increase approved in August, 1997 (which mirrors the permanent rate increase approved by this order) Pennichuck will see a total 16.77% increase in revenues and general metered core customers will see a total 20.77% increase in rates over those in effect prior to the filing of the rate case in the summer of 1997. The billing impact for core customers as of April 1, 1998, however, will be 12.97%, given that 7.8% of the increase has already been included in rates as of the temporary rate order last August. As of April 1, 1998, community system customers will see increases or decreases in their bills according to whether their community system rate had been above or below the consolidated rate of approximately $253 per year.

Finally, we emphasize that by approving rate consolidation in this case, we are not accepting it as a generic policy for all water companies.

Based upon the foregoing, it is hereby

ORDERED, that the Settlement Agreement reached between Pennichuck and Staff is APPROVED; and it is

FURTHER ORDERED, that Pennichuck's rate consolidation proposal is APPROVED; and it is

FURTHER ORDERED, that Pennichuck shall file its final rate case expense request within five days for Staff review and Commission consideration; and it is

FURTHER ORDERED, that Pennichuck shall submit a compliance tariff within five days in conformance of this order.

By order of the Public Utilities Commission of New Hampshire this twenty-fifth day of March, 1998.

Douglas L. Patch	Bruce B. Ellsworth	Susan S. Geiger
Chairman	Commissioner	Commissioner

Attested by:

Thomas B. Getz
Executive Director and Secretary