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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 FURNISHED BY ITS NORTHERN GROUP AND FOR CERTAIN RELATED APPROVALS.	Docket No. W-01445A-12-0348

Arizona Corporation Commission
DOCKETED
MAR 1 2013
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RUCO'S NOTICE OF FILING

The RESIDENTIAL UTILITY CONSUMER OFFICE ("RUCO") hereby provides notice of filing the Direct Testimony of William A. Rigsby and Jorn Keller, in the above-referenced docket.

RESPECTFULLY SUBMITTED this 1st day of March, 2013.

Daniel W. Pozefsky
Chief Counsel

AN ORIGINAL AND THIRTEEN COPIES of the foregoing filed this 1st day of March, 2013 with:

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ARIZONA WATER COMPANY

DOCKET NO. W-01445A-12-0348

DIRECT TESTIMONY

OF

JORN L. KELLER

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MARCH 1, 2013

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EXECUTIVE SUMMARY

Arizona Water Company ("AWC" or "Company") is a Class A public service water corporation. Currently, the Company serves approximately 84,800 customers. AWC is comprised of eleven separate operating systems that are organized into three different geographical groups: Northern, Western and Eastern. AWC filed a general rate application with the Arizona Corporation Commission ("ACC" or "Commission") on August 1, 2012 for its Northern Group, utilizing a test year ending December 31, 2011. The Commission found the application sufficient and filed a Letter of Sufficiency on August 30, 2012.

The Company's Northern Group is comprised of the Navajo system (Lakeside and Overgaard) and the Verde Valley system (Sedona, Pinewood and Rimrock). The Northern Group serves approximately 19,700 customers in Yavapai, Coconino, and Navajo counties. AWC is requesting adjustments to rates and charges for utility service in each of the Northern Group's water systems. AWC's rate application uses a test year ending December 31, 2011, and it requests an increase in revenue of $2,829,974, a 27.95 percent increase.

In addition, AWC proposes full rate consolidation of the Sedona water system with Pinewood and Rimrock of the Verde Valley water system. Authorization is requested to continue the arsenic cost recovery mechanism ("ACRM"), as authorized in Decision No. 66400, for the Sedona and Rimrock facilities of the Verde Valley water system, and to extend the mechanism to the Navajo system as well. Authorization is requested to implement a Distribution System Improvement Charge ("DSIC"), to implement an Off Site Facilities Fees of $1,100 or more for new service connections and to continue the Monitoring Assistance Program ("MAP") surcharge previously authorized for the Northern Group.

The Company's gross revenue increase requests by system and RUCO's proposed amounts are as follows:

	AWC Requested		RUCO	
System	Increase	Percent	Recommended	Percent
Navajo	$4,373,361	21.65%	$4,025,491	9.87%
Verde Valley	$8,581,072	31.41%	$7,922,965	20.18%

AWC requests a 9.11 percent rate of return on the fair value rate base ("FVRB") on the Northern Group systems, while RUCO recommends an 7.81% rate of return The FVRB as identified by the Company and RUCO's recommendation is shown as follows:

SYSTEM	COMPANY PROPOSED FVRB	RUCO's PROPOSED FVRB
Navajo	$ 9,911,050	$ 9,227,096
Verde Valley	$26,134,793	$25,528,427

RUCO's Chief of Accounting and Rates, William A. Rigsby, will address the recommended cost of capital, as well as other requests of the Company, such as a continuation of the ACRM and its extension to the Navajo system, the distribution system improvement charge ("DSIC") and the Company-proposed off-site facility fees. RUCO witness, Robert B. Mease, will provide testimony on RUCO's recommended rate design.

INTRODUCTION

Q. Please state your name, position, employer and address.

A. My Name is Jorn L. Keller. 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 state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background, work experience and regulatory matters in which I have participated. In summary, I joined RUCO in November of 2012. I graduated from Kansas State University with a degree in Political Science and from the University of Phoenix with an MBA. My years of work experience include employment as a Tax Analyst for the Arizona Department of Revenue and as a Compliance Auditor for the Arizona Department of Transportation.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding Arizona Water Company's ("AWC" or "Company") Northern Group's Application for a determination of the current fair value of its utility plant and property and for a permanent increase in its rates and charges for utility service. The test year utilized by the Company in connection with this Application is the 12-month period that ended December 31, 2011 (Test Year).

Q. How many and which systems are in the Company's Northern Group?

A. There are two systems in the AWC's Northern Group: Navajo and Verde Valley. The Navajo system consists of the previously consolidated Lakeside and Overgaard systems. The Verde Valley system is comprised of the previously consolidated Pinewood and Rimrock systems and the partially consolidated Sedona system. The Sedona system retains separate rates.

BACKGROUND

Q. Please describe your work effort on this project.

A. I reviewed financial data provided by the Company and performed analytical procedures necessary to understand the Company's filing as it pertains to operating income, rate base, and the overall revenue requirement for each system in the Northern Group. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of the aforementioned data, the review and analysis of the Company's responses to Commission and Staff data requests and the review of prior ACC dockets related to AWC's Northern Group and other groups of the Company. RUCO's participation in this proceeding is the cumulative effort of three RUCO witnesses: myself, Jorn L. Keller, William A. Rigsby and Robert B. Mease. I am responsible for the rate base and operating income and expense adjustments that determine RUCO's revenue requirement recommendations. RUCO's Chief of Accounting and Rates, Mr. Rigsby, will present separate testimony on policy related issues and RUCO's cost of capital recommendation. Mr. Mease is responsible for designing rates for all of the systems and will present RUCO's rate design testimony.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring schedules for the Northern Group systems numbered JLK-1 through JLK-18. Schedules are provided for each of the systems including Navajo (Lakeside and Overgaard) and Verde Valley (Sedona, Pinewood and Rimrock).

SUMMARY OF DIRECT TESTIMONY

Q. Please provide a summary of the Company's filing for each of the systems in the Northern Group.

A. The Company is proposing a fair value rate base ("FVRB") of $36,045,843 for the Northern Group and a 9.11 percent rate of return on the FVRB. For ratemaking purposes, the Company has elected not to perform a reconstruction cost, new less depreciation, study, and it is using its original cost rate base ("OCRB") as it's FVRB. The FVRB for each of the Northern Group systems as filed by the Company:

System	FVRB
Navajo (Lakeside and Overgaard)	$ 9,911,050
Verde Valley (Sedona, Pinewood and Rimrock)	$26,134,793
	$ 36,045,843

The Company also proposes an adjustment in rates that will increase operating revenues by $2,829,974 or a 27.95% percent overall increase from the test year for the Northern Group:

System	Proposed Operating Revenue	Increase From Test Year	Percentage Increase
Navajo	$ 4,373,361	$ 778,281	21.65 %
Verde Valley	$ 8,581,051	$ 2,051,475	31.42 %
	$ 12,954,412	$ 2,829,974	27.95 %

RATE BASE ADJUSTMENTS - SUMMARY

Q. Has RUCO recommended adjustments to the rate base for the systems in the Northern Group?

A. Yes, RUCO has recommended several adjustments to the rate base as filed by the Company.

Q. Can you please summarize RUCO's rate base adjustments and recommendations related to the Company's filing?

A. Yes, in summary, adjustments to the rate base that RUCO recommends include the following:

RUCO Rate Base Adjustment #1 – Post Test Year Plant

RUCO recommends an adjustment to reflect reductions in the value of post-test year plant. In AWC's Application, the Company estimated the cost of post-test year plant additions. When the final costs of the plant additions were determined, adjustments were necessary to reflect their actual costs. The final adjustments decreased the rate base in the Navajo and Verde Valley systems by $463,187 and $233,057 respectively.

RUCO Rate Base Adjustment #2 – Change in Cash Working Capital

This adjustment reduces the cash element of the working capital allowance requested by the Company for each of the Northern Group's systems as follows:

System	Working Capital Inc./Dec.
Navajo (Lakeside and Overgaard)	($220,768)
Verde Valley (Sedona, Pinewood and Rimrock)	($373,298)
Total Reduction	($ 594,066)

OPERATING INCOME ADJUSTMENTS – SUMMARY

Q. Has RUCO recommended adjustments to the operating income requested by the Company for the systems of the Northern Group?

A. Yes, RUCO has recommended several adjustments to the operating income filed by the Company.

Q. Please summarize RUCO's operating income adjustments in your testimony.

A. In summary, the adjustments to operating income that RUCO is recommending are as follows:

RUCO Operating Adjustment #1 –Transmission and Distribution Expense Normalization Adjustment - RUCO recommends a reduction in the Northern Group's normalization of Transmission and Distribution Expense. RUCO believes the methodology utilized by the Company to calculate the adjustment does not provide sufficient justification to support the adjustment. The number of years used in the calculation is inappropriate. RUCO's adjustments decreasing Transmission and Distribution Expense for each system are as follows:

Navajo	$ 40,077
Verde Valley	$ 40,585

RUCO Operating Adjustment #2 – Rate Case Expense - This adjustment reflects RUCO's recommended level of Rate Case Expense to be amortized over three years. RUCO's adjustment is the amount deemed reasonable by the Commission for the Northern Group in the prior rate case and with an adjustment for inflation. This adjustment decreases Rate Case Expense for each system as follows:

Navajo	$ 18,743
Verde Valley	$ 11,725

RUCO Operating Adjustment #3 – Fleet Fuel Expense – The Fleet Fuel adjustment is an attempt to smooth the fluctuating costs per gallon of gasoline and to arrive at an accurate test year cost. RUCO's data source[1] is the United States Energy Information Administration's average price for the months of January, 2012 through December, 2014. The price of gasoline has trended downward since the Company's initial filing. The use of a three year average produces an accurate fuel price for the test year. The adjustment decreases Fleet Fuel Expense for each system as follows:

Navajo	$ 134
Verde Valley	$1,378

RUCO Operating Adjustment #4 – Miscellaneous Expense – This adjustment removes certain expenses related to civic/service club dues, service awards associated with the year-end service award banquet, and 50 percent of water association fees. It is RUCO's opinion that these expenses should be paid by the Company not the ratepayers. This adjustment reduces administration expenses as follows:

Navajo	$ 4,872
Verde Valley	$ 4,743

RUCO Operating Adjustment #5 – Depreciation Expense – The depreciation adjustment calculates Depreciation and Amortization

[1] U. S. Energy Information Administration Short Term Energy Outlook.

Expense based on RUCO's recommended plant levels, including the Phoenix Office and Meter Shop. Depreciation Expense is adjusted for reductions or increases in utility plant in service, namely post-test year plant. Adjustments made by RUCO are as follows.

Navajo	$10,434
Verde Valley	$ 6,159

RUCO Operating Adjustment #6 – Declining Usage - The declining usage adjustment reduces operating income and expense for an anticipated drop in customer usage due to conservation and other causes. RUCO believes that this element is not known and measurable. In that regard, RUCO removed all adjustment for declining usage. Adjustments are as follows:

	Revenue	Expense
Navajo	$68,751	$15,249
Verde Valley	$63,203	$30,567
	$131,954	$45,816

RUCO Operating Adjustment #7 – 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 prior rate cases. The adjustment to Property Tax Expense for each system is an increase as follows:

Navajo	$ 2,306
Verde Valley	$ 2,178

RUCO Operating Adjustment #8 – Income Tax Expense – This adjustment calculates the appropriate level of Income Tax Expense given RUCO's recommended operating income. The adjustment to Income Tax Expense for each system is an increase as follows:

Navajo	$ 54,906
Verde Valley	$44,504

REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirements for the Northern Group systems.

A. RUCO recommends the following revenue increases or (decreases):

System	Rev. Increase	Pct. Increase/(Decrease)
Navajo	$ 361,659	9.87 %
Verde Valley	$ 1,330,169	20.18%
	$ 1,691,828	16.50 %

RATE BASE ADJUSTMENTS

Q. Does RUCO recommend changes to the Company's proposed rate base?

A. Yes. RUCO analyzed the Company's rate base adjustments to the test year and made adjustments to the rate base as filed by the Company. A summary and analysis of RUCO's adjustments is presented on the following pages.

Rate Base Adjustment # 1 Post Test Year Plant

Q. Did RUCO make adjustments related to post-test year plant additions included in the rate base for the AWC's systems?

A. Yes. RUCO made two types of adjustments to post-test year plant. First, the Company's post-test year adjustments for the Navajo and Verde Valley systems are based on estimated costs as identified on Schedule JLK-6. Final costs were identified by the Company after the Application was filed and reported in Staff Data Request JMM 1-21. Each project's estimated cost was then subtracted from the actual cost to arrive at RUCO's adjustment. Secondly, it is RUCO's opinion that plant constructed over six months after the end of the test year should not be added to rate base. Construction projects completed after June 30, 2012 were not accepted. Total adjustments reduced the rate base for the Navajo system by $463,187 and the Verde Valley system by $233,057.

RUCO Rate Base Adjustment #2 – Cash Working Capital

Q. Please explain the concept of Cash Working Capital.

A. Cash Working Capital is defined as the net cash outlay that a utility must furnish to provide service before payment for that service is received from the customers. The Cash Working Capital Requirement is the amount of cash the company must have on hand to cover differences in the time period between when revenues are received and expenses are paid. The most accurate measurement of the cash working capital requirement is the lead/lag study. The lead/lag study measures the actual lead and lag days attributable to revenues and expenses.

Q. Is RUCO proposing a Cash Working Capital Requirement adjustment in this case?

A. Yes. RUCO proposes a reduction in Cash Working Capital for each system. These adjustments are shown on Schedules JLK-5 and JLK-6(1).

Q Did AWC file a lead/lag study supporting its requested Cash Working Capital requirements in this case?

A. Yes, and RUCO confirmed the calculations made by the Company in developing their working capital requirements.

Q. What element of expenses did RUCO adjust in its lead/lag study?

A. RUCO made several operating expense adjustments that are reflected in RUCO's recommended lead/lag expense levels on Schedules JLK-5 and JLK-6(1). The sole expense adjustment not reflected in RUCO's lead/lag study is the Rate Case Expense adjustment.

Q. **Why doesn't RUCO include Rate Case Expense in the operating expenses of RUCO's lead/lag study?**

A. Rate Case Expense has already been incurred and paid. Consequently, it is not an appropriate expense to be included in the calculation of Cash Working Capital.

Q. Did RUCO make any other adjustments to elements in the lead/lag study?

A. Yes, RUCO made adjustments to Federal and State income taxes. RUCO also recommends several rate base adjustments, as discussed in RUCO Rate Base Adjustment #1, that are reflected in RUCO's lead/lag calculation for the recommended level of synchronized interest.

Q. Did the Company include interest expense in its working capital calculation?

A. No. The Company did not include interest expense in its calculation.

Q. What is RUCO's rationale for including the interest expense in the lead/lag study?

A. Interest payments are contractual arrangements associated with AWC's debt issuances that obligate the Company to make fixed interest payments on certain dates. In this respect, debt interest closely resembles AWC's other cash operating expenses. Thus, the payment lead for AWC's interest expense should be separately recognized in the lead/lag calculation as the Commission has recognized in numerous cases. Typically, long-term debt interest is paid semi-annually, creating a 91.25-day expense lag.

Q. Did the Company utilize the 91.25-day lag in calculating its interest expense for cash working capital?

A. Yes.

Q. What adjustments are necessary to cash working capital when taking all of RUCO's recommendations into consideration?

A. The total adjustment for all Northern Group systems related to Working Capital adjustments and resultant rate base is a reduction of $594,066 as indicated in my summary testimony.

OPERATING INCOME ADJUSTMENTS

RUCO Operating Adjustment #1 –Transmission and Distribution Expense Normalization Adjustment

Q. Did the Company normalize Transmission and Distribution Maintenance Expense?

A. Yes.

Q. What methodology was used in AWC's normalization process?

A. The Company's adjustment to Transmission and Distribution maintenance expense is based on linear trend O.L.S. regression analysis, using maintenance expense data for the years 1992 through 2011. Average maintenance cost per customer is calculated for the years 2013 through 2015 and averaged. The test year maintenance cost is then subtracted from the projected cost to form AWC's adjustment.

Q. Does RUCO take exception with the Company's normalization method?

A. Yes, RUCO objects to the methodology used. First, the regression model relies on 20 years of past data, an unusually long time period for the X axis. The use of a shorter X axis, a 10 year time period rather than 20, produces a much flatter trend line. For example, projected costs per customer in the Navajo system decline from $22 per customer to $18. Had the Company used a smaller sample, a lower projected cost per customer would have resulted. Moreover, while maintenance costs were projected by linear trend analysis, population growth, indicating increased revenue, was not. From 1992 through 2011, the Verde system showed a consistent, geometric growth in customer population, with the exception of declines of fewer than 50 customers in 2009 and 2011. The smaller Navajo system showed only one year of decline. Revenue from an increasing customer base would offset many maintenance expenses.

Q. Why is the Company normalizing these expenses?

A. As described in its testimony the Company implemented a number of significant cost-cutting measures in response to the economic downturn beginning in 2008, including a focused reduction in the level of costs incurred in the maintenance of the Company's T&D systems. Test year maintenance expenses were lower than some previous years.

Q. Does RUCO have a recommendation for normalizing these expenses.

A. Yes, RUCO reviewed the justification for normalizing these expenses and performed its own calculations. RUCO averaged T&D maintenance expense for the years, 2009 through 2011 and subtracted the test year expense. RUCO recommends that an average of the three years be approved. The Company made proforma adjustments of $134,940 for the

Northern Group while RUCO's recommends $80,662 as the proper amount to normalize pumping, transmission and distribution maintenance.

RUCO Operating Adjustment #2 – Rate Case Expense

Q. What is the amount of AWC's proposed rate case expense and how does it compare to RUCO's recommendation?

A. The Company proposes Rate Case Expense, for the Northern Group of $441,576. This amount is allocated to both of the systems on a per customer basis. RUCO recommends a Rate Case Expense of $283,391. Both RUCO and the Company propose that the expense be normalized over a three-year period.

Q. How did RUCO determine its recommended level of fair and reasonable Rate Case Expense?

A. RUCO started with, $216,982, the amount ordered in Commission Decision No. 64282, the last rate case filed by the Northern Group. It then applied the Consumer Price Index ("CPI") inflation factor per InflationData.com from January, 2002, date of the last decision, through August, 2012, the date of the Company's current application. The cumulative inflation factor is 30.66%. $283,391 represents the $216,982 Rate Case Expense found to be reasonable in the Northern Group's previous rate case multiplied by 1.3066.

RUCO Operating Adjustment #3 – Fleet Fuel Expense

Q. Can you please explain RUCO's adjustment to the Company-proposed level of Fleet Fuel Expense?

A. RUCO's adjustment to the Company-proposed level of Fleet Fuel Expense normalizes the volatile cost of gasoline for the test year period. The Company uses a test year price per gallon of $3.5530, its total cost of fuel in the test year, 2011. RUCO adjusted the price to $3.4680, the price indicated by the Energy Information Administration's three year average.

Q. What is the effect of RUCO's adjustment to Fleet Fuel Expense?

A. RUCO's adjustment reduces Fleet Fuel Expense by $1,512 for the entire Northern Group. The adjustment involves each of the Northern Group's systems, and it is identified on Schedule JLK-12 of Navajo and Verde Valley systems. The adjustment affects six expense categories on the Company's income statement. The expense categories affected are Source of Supply, Pumping Expenses, Water Treatment Expenses, Transmission & Distribution Expenses, Customer Accounting Expenses, and Administrative and General Expenses.

Q. The cost of gasoline has been extremely volatile over past years. Did this fact influence your adjustment for Fleet Fuel Expense?

A. Yes, in light of the gasoline price volatility of past years, RUCO believes that use of the U.S Energy Administration's projected 36 month average is the most accurate reflection of test year fuel expense

RUCO Operating Adjustment #4 – Miscellaneous Expense

Q. Please explain RUCO's adjustment to Miscellaneous Expense.

A. RUCO's Miscellaneous Expense adjustment removes certain expenses more appropriately absorbed by the shareholders.

Q. What type of Miscellaneous Expenses did RUCO remove?

A RUCO removed civic/service club dues, fees, donations, costs for flowers purchased and annual service award banquet costs. These are expenses that the ratepayer should not be required to pay in their cost of service. In addition, water associations' fees and dues were reduced by 50 percent to be shared by the shareholder and ratepayer. RUCO has proposed, and the Commission has accepted, this percentage allocation in prior rate cases. RUCO believes this is a fair allocation between Company and ratepayers.

RUCO Operating Adjustment #5 – Depreciation Expense

Q. Have you recalculated test year Depreciation and Amortization Expense?

A. RUCO agrees with the Company's Test Year Depreciation and Amortization Expense as calculated.

Q. Was a depreciation expense adjustment required once the Post-Test Year plant final costs were determined?

A. Yes, depreciation expense adjustments were made for both the Navajo and Verde Valley systems. Post test year plant additions were depreciated based on estimated costs of construction. Depreciation expense was recalculated once final costs were known and reported by the Company by data request.

RUCO Operating Adjustment #6 – Declining Usage

Q. Did the Company adjust test year operating income to compensate for Declining Usage?

A. Yes. The Company believes that a trend in declining utility usage of approximately 2% per year for the Northern Group exists. In that regard, AWC has decreased test year operating revenue by $131,954 and decreased operating expenses by $45,816.

Q. Does RUCO agree with the Company's treatment of Declining Usage?

A. No. RUCO believes that Declining Usage is not a known and measureable determinant. While AWC believes the decline in usage is due to weather patterns and water-saving appliances, RUCO suggests that the reasons for decline are temporary fluctuations in economic growth and population growth. As such, Declining Usage cannot be predicted accurately, and it should not be used to reduce test year revenue. As a result, RUCO adjusted the test year operating income by removing income and expense adjustments for Declining Usage.

RUCO Operating Adjustment #7 – Property Tax Expense

Q. Has RUCO changed its method of computing Property Tax Expense for the adjusted Test Year?

A. Yes, RUCO has adopted the method Staff has used in several recent rate cases. This method of computing Property Tax Expense affects the adjusted test year income taxes and the computation of the gross-up factor. The computation was adopted by RUCO in the spirit of compromise and to eliminate issues of comparability of the test year level of adjusted operating expense and adjusted operating income.

Q. Has RUCO adjusted the Company's-proposed level of Property Tax Expense?

A. Yes. RUCO's adjustment varies from the amount proposed by the Company. The reason for the variance is the difference in AWC's and RUCO's proposed levels of revenue. The details of these computations are shown on Schedules JLK-16.

RUCO Operating Adjustment #8 – 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 Schedules JLK-17 for the two systems in the Northern Group.

Q. Have you included an interest synchronization calculation in your computation of Income Tax Expense?

A. Yes. The interest synchronization calculation, scheduled on JLK-1(1), computes an interest expense deduction for income tax purposes. The interest synchronization calculation is the adjusted rate base multiplied by the weighted cost of debt. The income tax gross up revenue conversion factor includes an element for the increase in property taxes due to RUCO's recommended level of increased revenues as discussed in the property tax expense adjustment #7 above.

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's Northern Group?

A. Yes, it does.

APPENDIX I

JORN L. KELLER

Professional Qualifications

Education & Certifications

Master of Business Administration
University of Phoenix

Bachelor of Science -- Political Science
Kansas State University

Completion of 33 hours of Accounting, Finance and Economics

Certified Fraud Examiner
Certified Internal Auditor candidate
American Bar Association-certified Paralegal

Volunteer for the Arizona Attorney General's Consumer Protection Program

Professional Experience

Arizona Residential Utilities Consumer Office
Public Utilities Analyst V

- Analyze the rate case applications of Arizona utilities
- Calculate adjustments to rate base and operating income
- Prepare written testimony filed with the Arizona Corporation Commission
- Testify in utility rate hearings

Arizona Department of Transportation
Compliance Auditor

- Audited large construction projects to assure fund allocation and compliance
- Audited local businesses for Rental Vehicle Surcharge Tax. Examined financial records, calculated tax assessments and wrote audit reports.

Arizona Department of Revenue
TPT (Sales) Tax Analyst

- Conducted field audits to ensure business compliance with Arizona transaction privilege and use tax laws
- Audited business accounting records in accordance to Generally Accepted Accounting Principles, Generally Accepted Auditing Standards and ADOR policy to determine transactional privilege tax liability
- Researched the Arizona Revised Statutes, the Arizona Administrative Code, the Model City Tax Code and TPRs in regard to various legal issues of transaction privilege and use tax
- Recreated the activity of the audit period in a complex computer software program and drafted a detailed narrative report of the audit activity
- Presented the audit findings and assessment to the taxpayer or their representative and counseled the taxpayer on proper TPT filing procedure.
- Represented the Department in audit appeals

M&I Bank
Credit Analyst & Legal Analyst

- Conducted a variety of legal, compliance and credit activities for a commercial bank
- Analyzed financial statements of corporations and individuals
- Assisted in state and federal compliance exams
- Responded to subpoenas, garnishments, levies and other pleadings
- Filed Suspicious Activity Reports

Maricopa County Public Fiduciary
Senior Estate Administrator

- Supervised asset managers and administered a caseload conservatorship and probate estates.
- Coordinated litigation activities with the County Attorney and counsel.
- Investigated assets, compiled forensic accountings, drafted court reports and testified in Superior Court.

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JLK-6(1)	1	RATE BASE ADJUSTMENT NO. 2 - WORKING CAPITAL
JLK-7	1	OPERATING INCOME
JLK-8	1 & 2	SCHEDULE OF OPERATING INCOME - TEST YEAR WITH RUCO ADJUSTMENTS
JLK-9	1 & 2	SCHEDULE OF OPERATING INCOME-TEST YEAR COMPANY ADJUSTMENTS
JLK-10	1	OPERATING INCOME ADJUSTMENT NO. 1 - TRANSMISSION & DISTRIBUTION EXPENSE NORMALIZATION
JLK-11	1	OPERATING INCOME ADJUSTMENT NO. 2 - RATE CASE EXPENSE
JLK-12	1	OPERATING INCOME ADJUSTMENT NO. 3 - FLEET FUEL ADJUSTMENT
JLK-13	1	OPERATING INCOME ADJUSTMENT NO. 4 - MISCELLANEOUS EXPENSE
JLK-14	1	OPERATING INCOME ADJUSTMENT NO. 5 - DEPRECIATION EXPENSE ADJUSTMENT
JLK-15	1	OPERATING INCOME ADJUSTMENT NO. 6 - DECLINING USAGE
JLK-16	1	OPERATING INCOME ADJUSTMENT NO. 7 - PROPERTY TAXES
JLK-17	1	OPERATING INCOME ADJUSTMENT NO. 8 - INCOME TAXES
JLK-18	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	$	9,911,050	$	9,227,096
2					
3	Adjusted Operating Income (Loss)	$	430,276	$	500,828
4					
5	Current Rate of Return (L3 / L1)		4.34%		5.43%
6					
7	Required Operating Income (L9 X L1)	$	902,842	$	720,424
8					
9	Required Rate of Return on Fair Value Rate Base		9.11%		7.81%
10					
11	Operating Income Deficiency (L7 - L3)	$	472,566	$	219,596
12					
13	Gross Revenue Conversion Factor (JLK-1, Page 2 of 2)		1.6469		1.6469
14					
15	Required Increase in Gross Revenue Requirement (L11 X L13))	$	778,281	$	361,659
16					
17	Adjusted Test Year Revenue	$	3,595,002	$	3,663,832
18					
19	Proposed Annual Revenue (L15 + L17)	$	4,373,361	$	4,025,491
20					
21	Required Percentage Increase in Revenue (L15 / L17)		21.65%		9.87%
22					
23	Consolidated Revenue Adjustment	$	-	$	-
24					
25	Required Increase in Gross Revenue Under Proposed Consolidation	$	-	$	-
26					
27	Required Revenue Under Proposed Consolidation	$	-	$	-
28					
29	Required Percentage Increase in Revenue Under Proposed Consolidation		0%		0%
30					
31	Rate of Return on Common Equity		11.30%		8.75%

References:
Column (A): Company Schs. A-1 and C-1
Column (B): RUCO Schs. JLK-2, JLK-7, and JLK-18

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:			
1	Revenue	100.0000%		
2	Proposed Bad Debt Expense (Per Co. Workpapers)	-		
3	Subtotal (L1 thru L2)	100.0000%		
4	Combined Federal, State, Property Tax Rate (L22)	39.2808%		
5	Subtotal (L3 - L4)	60.7192%		
6	**Revenue Conversion Factor** (L1 / L5)	**1.6469**		
7				
8	***CALCULATION OF EFFECTIVE TAX RATE:***			
9	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%		
10	Arizona State Income Tax Rate	6.9680%		
11	Federal Taxable Income (L9 - L10)	93.0320%		
12	Applicable Federal Income Tax Rate (L58)	34.0000%		
13	Effective Federal Income Tax Rate (L11 X L12)	31.6309%		
14	Combined Federal and State Income Tax Rate (L10 + L13)	38.5989%		
15				
16	***CALCULATION OF EFFECTIVE PRPERTY TAX FACTOR:***			
17	Unity	100.0000%		
18	Combined Federal and State Tax Rate	38.5989%		
19	1 Minus Combined Income Tax Rate	61.4011%		
20	Property Tax Factor	1.1107%		
21	Effective Property Tax Factor (L19 x L 20)	0.6820%		
22	Combined Federal, State & Property Tax RateTax Rate (L14 + L21)	39.2808%		
23				
24	RUCO Required Operating Income (Sch. JLK-1, Col. (B), L7)	$ 720,424		
25	RUCO Adj'd T.Y. Oper'g Inc. (Loss) (Sch. JLK-1, Col. (B), L3)	500,828		
26	Required Increase In Operating Income (L24 - L25)		$ 217,258	
27				
28	Income Taxes On Recommended Revenue (Col. (C), L53)	$ 257,638		
29	Income Taxes On Test Year Revenue (Col. (C), L55)	117,254		
30	Required Increase In Revenue To Provide For Income Taxes (L28 - L29)		$ 140,384	
31				
32	Property Tax with Recommended Revenue (Sch. JLK-7, Col. E, L31)	126,096		
33	Propertry Tax on TestYear Revenue (Sch. JLK-7, Col. C, L31)	122,079		
34	Increase in Property Tax Due to Increase in Revenue (L32 - L33)		$ 4,017	
35				
36	Total Required Increase In Revenue (L26 + L30 + L34)		$ 361,659	

LINE NO.	DESCRIPTION	RUCO Test Year	RUCO Recommended
37		**R U C O**	
38	***RUCO's CALCULATION OF INCOME TAX:***	**Test Year**	**Recommended**
39	RUCO Revenue (Sch. JLK-1, Col. (B), L19)	$ 3,663,832	$ 4,025,491
40	**Less:**		
41	Operating Expense Excluding Income Tax (Sch. JLK-7, Col. (E), L24 + L26 + L31 + L32)	3,045,750	3,049,767
42	Synchronized Interest (Col. (C), L63)	308,250	308,250
43	Arizona Taxable Income (L39 - L41 - L42)	$ 309,832	$ 667,474
44	Arizona State Income Tax Rate	6.9680%	6.9680%
45	Arizona Income Tax (L43 X L44)	$ 21,589	$ 46,510
46	Fed. Taxable Income (L43 - L45)	$ 288,243	$ 620,964
47	Fed. Tax On 1st Inc. Bracket ($1 - $50,000) @ 15%	$ 7,500	$ 7,500
48	Fed. Tax On 2nd Inc. Bracket ($50,001 - $75,000) @ 25%	$ 6,250	$ 6,250
49	Fed. Tax On 3rd Inc. Bracket ($75,001 - $100,000) @ 34%	$ 8,500	$ 8,500
50	Fed. Tax On 4th Inc. Bracket ($100,001 - $335,000) @ 39%	$ 73,415	$ 91,650
51	Fed. Tax On 5th Inc. Bracket ($335,001 - $10M) @ 34%	$ -	$ 97,228
52	Total Federal Income Tax (L47 thru L 51)	$ 95,665	$ 211,128
53	Combined Federal And State Income Tax (L45+ L52)	$ 117,254	$ 257,638
54			
55	Adjusted TY Combined Federal and State Income Tax (JLK-7, Col. (C), L29 and L30)		$ 117,254
56	RUCO Proposed Income Tax Adjustment (L53 - L55)		$ 140,384
57			
58	Applicable Federal Income Tax Rate		
59			
60	**NOTE (A): Interest Synchronization**		
61	Adjusted Rate Base JLK-2, Col. (C), L28		$ 9,227,095
62	Weighted Cost Of Debt JLK-18, Col. (F), L1		3.34%
63	Interest Expense (L61 X L62)		$ 308,250

SUMMARY RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
1	Plant Classification			
2	Intangible Plant	$ 2,809	$ -	$ 2,809
3	Source of Supply Plant	2,339,748	(50,000)	2,289,748
4	Pumping Plant	2,930,524	(40,000)	2,890,524
5	Water Treatment Plant	198,557	(50,000)	148,557
6	Transmission & Distribution Plant	22,804,984	(115,609)	22,689,375
7	General Plant	1,946,759	(218,012)	1,728,747
8	Total Gross Plant in Service (L2 thru L7)	$ 30,223,381	$ (473,621)	$ 29,749,760
9				
10	Accumulated Depreciation	$ 9,719,013	$ (10,434)	$ 9,708,579
11	Net Utility Plant In Service (L8 - L10)	$ 20,504,368	$ (463,187)	$ 20,041,181
12				
13	Advances In Aid Of Const.	$ 3,416,251	$ -	$ 3,416,251
14				
15	Contribution In Aid Of Const.	$ 6,338,423	$ -	$ 6,338,423
16	Accumulated Amortization Of CIAC	$ (1,479,824)	$ -	$ (1,479,824)
17	NET CIAC (L15 + L16)	$ 4,858,599	$ -	$ 4,858,599
18				
19	Deferred Income Tax	$ 2,752,278	$ -	$ 2,752,278
20				
21	Customer Deposits	$ 21,020	$ -	$ 21,020
22				
23	Allowance For Working Capital	$ 454,831	$ (220,768)	$ 234,063
24				
25	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
26				
27	Adjustment to Match Rate Base with G/L	$ -	$ -	$ -
28	TOTAL RATE BASE (L11-L13-L17-L19-L21+L23+L25)	$ 9,911,051	$ (683,955)	$ 9,227,096

References:
Column (A): Company Schedule B-1 and JLK-3 Col. E
Column (B): Schedule JLK-3 Cols. G and H
Column (C): Col. A + Col. B; JLK-3

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Navajo (Lakeside, Overgaard)
Schedule JLK-3
Page 1

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED NET PLANT TEST YEAR	(B) COMPANY ADJ NO 1 POST TEST YEAR ADJUSTMENTS	(C) COMPANY ADJ NO 2 PHOENIX OFF AND METER SHOP	(D) BLANK	(E) COMPANY AS FILED OCRB/FVRB	(F) RUCO ADJMT NO. 1 POST TEST YR ADJUSTMENTS	(G) RUCO ADJMT NO. 2 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
1	Plant Classification								
2	Intangible Plant	$ 1,946	$ -	$ 863		$ 2,809	$ -	$ -	2,809
3	Source of Supply Plant	2,289,740	50,000	8		2,339,748	(50,000)	-	2,289,748
4	Pumping Plant	2,890,524	40,000	-		2,930,524	(40,000)	-	2,890,524
5	Water Treatment Plant	148,363	50,000	193		198,556	(50,000)	-	148,556
6	Transmission & Distribution Plant	22,654,431	149,981	572		22,804,984	(115,609)	-	22,689,375
7	General Plant	1,033,523	217,891	695,345		1,946,759	(218,012)	-	1,728,747
8	Total Gross Plant in Service (Sum L2 thru L7)	$ 29,018,527	$ 507,872	696,981		$ 30,223,380	$ (473,621)	$ -	$ 29,749,758
9									
10	Accumulated Depreciation	$ 9,516,521	11,259	191,233		$ 9,719,013	(10,434)	-	9,708,578
11	Net Utility Plant In Service (L8 less L10)	$ 19,502,006	$ 496,613	$ 505,748		$ 20,504,367	$ (463,187)	$ -	$ 20,041,180
12									
13	Advances In Aid Of Const.	$ 3,416,251	$ -	$ -		$ 3,416,251	$ -	$ -	3,416,251
14									
15	Contribution In Aid Of Const.	6,338,423	$ -	$ -		$ 6,338,423	$ -	$ -	6,338,423
16	Accumulated Amortization Of CIAC	(1,479,824)	-	-		$ (1,479,824)	-	-	(1,479,824)
17	NET CIAC (L15 less L16)	$ 4,858,599	$ -	$ -		$ 4,858,599		$ -	$ 4,858,599
18									
19	Deferred Income Tax	$ -	$ -	$ 2,752,278		$ 2,752,278	$ -	$ -	$ 2,752,278
20									
21	Customer Deposits	$ 21,020	$ -	$ -		$ 21,020	$ -	$ -	$ 21,020
22									
23	Allowance For Working Capital	$ 454,831	$ -	$ -		$ 454,831	$ -	$ (220,768)	$ 234,063
24									
25	Net Regulatory Asset / (Liability)	$ -	$ -			$ -	$ -	$ -	$ -
26									
27	Adjustment to Match Rate Base with G/L	$ -	$ -	$ -		$ -	$ -	$ -	$ -
28	TOTAL RATE BASE (Sum L's 11, 13, 17, 19, 21, 23, 25 27)	$ 11,660,967	$ 496,613	$ (2,246,530)		$ 9,911,050	$ (463,187)	$ (220,768)	$ 9,227,095

References:
Columns (A) through (E): Company Schedule B-2
Column (F): RUCO Schedule JLK-6, Col. E
Column (G): RUCO Schedule JLK-5, Col. A

Arizona Water Company
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DIRECT PLANT AND ACCUMULATED DEPRECIATION

Line No.	Acct. No.		Depreciation Rate Dec. 64282 01/01/02 To 7/31/10	Depreciation Rate Dec. 71845 08/01/10 To Present	Starting Point for Plant Rec. 12/31/2007	2008 Additions	2008 Retirements	2008 Adjustments	2008 Depreciation Expense	2008 Balance	2009 Additions	2009 Retirements	2009 Adjustments	2009 Depreciation Expense	2009 Balance
1		Intangible Plant													
2	301	Organization	0.00%	0.00%	-	-	-	-	-	-	-	-	-	-	-
3	302	Franchises	See Acct. 11	See Acct. 111	-	-	-	-	-	-	-	-	-	-	-
4	303	*Other Intangibles*	See Acct. 11	See Acct. 111	1,946	-	-	-	97	1,946	-	-	-	97	1,946
5		Subtotal Intangible Plant			1,946	-	-	-	97	1,946	-	-	-	97	1,946
6		Source of Supply Plant													
7	310.1	Water Rights	0.00%	0.00%	337,104	153,334	-	-	-	490,438	10,183	-	-	-	500,621
8	310.3	Other Source of Supply Land	0.00%	0.00%	30,155	-	-	-	-	30,155	-	-	-	-	30,155
9	310.4	Wells - Other	See Acct. 11	See Acct. 111	-	-	-	-	-	-	-	-	-	-	-
10	314	Wells	2.59%	3.13%	2,072,642	-	-	-	53,681	2,072,642	-	-	-	53,681	2,072,642
11		Subtotal Source of Supply Plant			2,439,901	153,334	-	-	53,681	2,593,235	10,183	-	-	53,681	2,603,418
12		Pumping Plant													
13	320	Pumping Plant Land	0.00%	0.00%	8,553	-	-	-	-	8,553	-	-	-	-	8,553
14	321	Pumping Plant Structures & Improvements	2.59%	2.86%	146,333	108	-	-	3,791	146,441	2,854	(2,347)	-	3,799	146,948
15	325	Electtric Pumping Equipment	2.59%	5.88%	2,618,052	137,201	(47,502)	-	68,969	2,707,751	320,915	(377,122)	-	69,403	2,651,544
16	328	Gas Engine Equipment	2.59%	4.00%	-	-	-	-	-	-	-	-	-	-	-
17		Subtotal Pumping Plant			2,772,938	137,309	(47,502)	-	72,760	2,862,745	323,769	(379,469)	-	73,202	2,807,045
18		Water Treatment Plant													
19	330	Water Treatment Plant Land	0.00%	0.00%	-	-	-	-	-	-	-	-	-	-	-
20	331	Water Treatment Structures & Improvements	2.59%	2.50%	563	-	-	-	15	563	-	-	-	15	563
21	332	Water Treatment Equipment	2.59%	2.86%	130,564	715	-	-	3,391	131,279	1,291	-	-	3,417	132,570
22		Subtotal Water Treatment Plant			131,127	715	-	-	3,406	131,842	1,291	-	-	3,432	133,133
23		Transmission & Distribution Plant													
24	340	Transmission and Distribution Land	0.00%	0.00%	53,126	-	-	-	-	53,126	-	-	-	-	53,126
25	342	Storage Tanks	2.59%	2.00%	1,338,226	-	-	-	34,660	1,338,226	-	-	-	34,660	1,338,226
26	343	Transmission & Distribution Mains	2.59%	1.79%	12,450,047	1,513,620	(5,802)	-	341,982	13,957,865	129,783	(4,232)	-	363,135	14,083,416
27	344	Fire Sprinkler Taps	2.59%	2.00%	117,428	22,678	-	-	3,335	140,106	16,675	-	-	3,845	156,781
28	345	Services	2.59%	2.38%	4,219,020	476,407	(1,554)	-	115,422	4,693,873	123,742	(703)	113	123,166	4,817,025
29	346	Meters	2.59%	4.55%	550,915	14,116	(2,261)	-	14,422	562,770	5,416	(2,469)	-	14,614	565,717
30	348	Hydrants	2.59%	1.82%	1,241,434	145,250	(2,399)	-	34,003	1,384,285	4,912	-	-	35,917	1,389,197
31		Subtotal Transmission & Distribution Plant			19,970,196	2,172,071	(12,016)	-	543,825	22,130,251	280,528	(7,404)	113	575,337	22,403,488
32		General Plant													
33	389	*General Plant Land*	0.00%	0.00%	1,995	-	-	-	-	1,995	-	-	-	-	1,995
34	390	General Plant Structures	2.59%	2.50%	320,029	542	-	-	8,296	320,571	3,099	-	-	8,343	323,670
35	390.1	Leasehold Improvements	See Acct. 108	See Acct. 108.2	54,546	-	-	-	3,157	54,546	88	-	-	3,171	54,634
36	391	Office Furniture & Equipment	2.59%	6.67%	216,411	417	-	-	5,610	216,828	309	(30)	-	5,619	217,107
37	393	Warehouse Equipment	2.59%	5.00%	3,512	-	-	-	91	3,512	-	-	-	91	3,512
38	394	Tools, Shop & Garage Equipment	2.59%	4.00%	106,721	314	-	-	2,768	107,035	776	(88)	-	2,781	107,723
39	395	Laboratory Equipment	2.59%	5.00%	783	-	-	-	20	783	-	-	-	20	783
40	396	Power Operated Equipment	2.59%	6.67%	8,570	291	(189)	-	223	8,672	538	-	-	232	9,210
41	397	Communication Equipment	2.59%	6.67%	243,365	4,097	-	-	6,356	247,462	888	-	-	6,421	248,350
42	398	Miscellaneous Equipment	2.59%	3.33%	36,489	-	-	-	945	36,489	-	-	-	947	36,489
43		Subtotal General Plant			992,421	5,661	(189)	-	27,467	997,893	5,698	(118)	-	27,625	1,003,473
44		Plant in Service			$ 26,308,529	$ 2,469,090	$ (59,707)	$ -	$ 701,236	$ 28,717,912	$ 621,469	$ (386,991)	$ 113	$ 733,374	$ 28,952,503
45									270					354	
46		Accumulated Depreciation & Amort.			$ 7,534,114				$ 8,175,913					$ 8,522,651	
47		Net Plant in Service			$ 18,774,415	$ 2,469,090	$ (59,707)	$ -		$ 28,717,912	$ 621,469	$ (386,991)	$ 113		$ 28,952,503

References:

Company response to RUCO Data Request 1.14
Confirmed Company Calculations as Correct
Depreciation Rates Agrees with Respective Decisions

DIRECT PLANT AND ACCUMULATED DEPRECIATION

Line No.	Acct. No.		Depreciation Rate Dec. 64282 01/01/02 To 7/31/10	Depreciation Rate Dec. 71845 08/01/10 To Present	2010 Additions	2010 Retirements	2010 Adjustments	2010 Depreciation Expense	2010 Balance	2011 Additions	2011 Retirements	2011 Adjustments	2011 Depreciation Expense	2011 Balance
1		Intangible Plant												
2	301	Organization	0.00%	0.00%	-	-	-	-	-	-	-		-	-
3	302	Franchises	See Acct. 11	See Acct. 111	-	-	-	-	-	-	-		-	-
4	303	Other Intangibles	See Acct. 11	See Acct. 111		-	-	97	1,946	-	-		97	1,946
5		Subtotal Intangible Plant			-	-	-	97	1,946	-	-	-	97	1,946
6		Source of Supply Plant												
7	310.1	Water Rights	0.00%	0.00%	-	-	(8)	-	500,613	125	-	-	-	500,738
8	310.3	Other Source of Supply Land	0.00%	0.00%	-	-	-	-	30,155	-	-	-	-	30,155
9	310.4	Wells - Other	See Acct. 11	See Acct. 111	-	-	-	-	-	-	-	-	-	-
10	314	Wells	2.59%	3.13%	28	-	(313,824)	58,345	1,758,846	-	-	-	55,052	1,758,846
11		Subtotal Source of Supply Plant			28	-	(313,832)	58,345	2,289,614	125	-	-	55,052	2,289,739
12		Pumping Plant												
13	320	Pumping Plant Land	0.00%	0.00%	-	-	-	-	8,553	-	-	-	-	8,553
14	321	Pumping Plant Structures & Improvements	2.59%	2.86%	56	-	-	3,972	147,004	3,047	(120)	-	4,246	149,931
15	325	Electtric Pumping Equipment	2.59%	5.88%	233,400	(169,198)	-	106,295	2,715,746	56,235	(39,940)	-	160,165	2,732,041
16	328	Gas Engine Equipment	2.59%	4.00%	-	-	-	-	-	-		-	-	-
17		Subtotal Pumping Plant			233,456	(169,198)	-	110,267	2,871,303	59,282	(40,060)	-	164,411	2,890,525
18		Water Treatment Plant												
19	330	Water Treatment Plant Land	0.00%	0.00%			-	-	-	-	-	-	-	-
20	331	Water Treatment Structures & Improvements	2.59%	2.50%	-	-	-	14	563	-	-	-	14	563
21	332	Water Treatment Equipment	2.59%	2.86%	14,727	(755)	-	3,771	146,542	2,814	(1,556)	-	4,209	147,800
22		Subtotal Water Treatment Plant			14,727	(755)	-	3,785	147,105	2,814	(1,556)	-	4,223	148,363
23		Transmission & Distribution Plant												
24	340	Transmission and Distribution Land	0.00%	0.00%	-	-	-	-	53,126	-	-	-	-	53,126
25	342	Storage Tanks	2.59%	2.00%	-	-	-	31,370	1,338,226	-	-	-	26,765	1,338,226
26	343	Transmission & Distribution Mains	2.59%	1.79%	1,521	(10,923)	-	317,710	14,074,014	25,774	(1,399)	-	252,143	14,098,389
27	344	Fire Sprinkler Taps	2.59%	2.00%	32,475	-	-	4,056	189,256	15,607	-	-	3,941	204,863
28	345	Services	2.59%	2.38%	79,420	(6,129)	-	121,463	4,890,316	90,806	(3,053)	-	117,434	4,978,069
29	346	Meters	2.59%	4.55%	3,113	(797)	-	19,312	568,033	6,664	(687)	-	25,981	574,010
30	348	Hydrants	2.59%	1.82%	8,225	(331)	-	31,613	1,397,091	11,598	(940)	-	25,524	1,407,749
31		Subtotal Transmission & Distribution Plant			124,754	(18,180)	-	525,524	22,510,062	150,449	(6,079)	-	451,788	22,654,432
32		General Plant												
33	389	General Plant Land	0.00%	0.00%		-	-	-	1,995	-	-	-	-	1,995
34	390	General Plant Structures	2.59%	2.50%		-	-	8,262	323,670	-	-	-	8,092	323,670
35	390.1	Leasehold Improvements	See Acct. 108	See Acct. 108.2	19,592	-	-	4,094	74,226	-	-	-	13259	74,226
36	391	*Office Furniture & Equipment*	2.59%	6.67%	1,825	(165)	-	9,349	218,767	482	(205)	-	14,601	219,044
37	393	Warehouse Equipment	2.59%	5.00%	-	-	-	126	3,512	-	-	-	176	3,512
38	394	Tools, Shop & Garage Equipment	2.59%	4.00%	856	-	-	3,436	108,579	1,536	-	-	4,374	110,115
39	395	Laboratory Equipment	2.59%	5.00%	1,907	-	-	62	2,690	-	-	-	135	2,690
40	396	Power Operated Equipment	2.59%	6.67%	1,252	-	-	422	10,462	-	-	-	698	10,462
41	397	*Communication Equipment*	2.59%	6.67%	2,172	-	-	10,701	250,522	270	-	-	16,719	250,792
42	398	Miscellaneous Equipment	2.59%	3.33%	526	-	-	1,065	37,015	-	-	-	1,233	37,015
43		Subtotal General Plant			28,130	(165)	-	37,517	1,031,438	2,288	(205)	-	59,285	1,033,521
44		Plant in Service			$ 401,095	$ (188,298)	$ (313,832)	$ 735,535	$ 28,851,468	$ 214,958	$ (47,900)	$ -	$ 734,856	$ 29,018,526
45														
46		Accumulated Depreciation & Amort.						(222,468) $ 8,847,420						510 $ 9,534,886
47		Net Plant in Service			$ 401,095	$ (188,298)	$ (313,832)		$ 28,851,468					$ 19,483,640

References:
Company response to RUCO Data Request 1.14
Confirmed Company Calculations as Correct
Depreciation Rates Agrees with Respective Decisions

PHOENIX OFFICE AND METER SHOP - ALLOCATION TO RATE BASE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED	(B) Navajo	(C) Verde Valley
1	3 Factor Allocation Factor		9.43%	12.52%
2	Phoenix Office Allocation			
3	Plant Classification			
4	Intangible Plant	$ 9,148	$ 863	$ 1,145
5	Source of Supply Plant	-	-	-
6	Pumping Plant	-	-	-
7	Water Treatment Plant	-	-	-
8	Transmission & Distribution Plant	-	-	-
9	General Plant	7,228,106	681,610	904,959
10	Total Gross Plant in Service (Sum L4 thru L9)	7,237,253	$ 682,473	$ 906,104
11	Less:			
12	Accumulated Depreciation	1,965,832	185,378	246,122
13	Net Utility Plant In Service (L10 less L12)	5,271,421	$ 497,095	$ 659,982
14	Less:			
15	Deferred Income Tax	29,186,404	$ 2,752,278	$ 3,654,138
16	Total Phoenix Office Allcoation (L13 less L15)	$ (23,914,983)	$ (2,255,183)	$ (2,994,156)
17				
18	Meter Shop Allocation			
19	Plant Classification			
20	Intangible Plant			
21	Source of Supply Plant	$ -	-	-
22	Pumping Plant	80	8	10
23	Water Treatment Plant	-	-	-
24	Transmission & Distribution Plant	2,050	193	257
25	General Plant	6,066	572	759
26	Total Gross Plant in Service (Sum L20 thru L25)	145,649	13,735	18,235
27	Less:	153,844	14,508	19,261
28	Accumulated Depreciation			
29	Net Utility Plant In Service (L26 less L28)	62,087	$ 5,855	$ 7,773
30	Less:	91,758	8,653	11,488
31	Deferred Income Tax		-	-
32	Total Phoenix Office Allcoation (L29 less L31)	$ 91,758	$ 8,653	$ 11,488
33				
34	Total Phoenix Office and Meter Shop Allocation			
35	Plant Classification			
36	Intangible Plant	$ 9,148	$ 863	$ 1,145
37	Source of Supply Plant	80	8	10
38	Pumping Plant	-	-	-
39	Water Treatment Plant	2,050	193	257
40	Transmission & Distribution Plant	6,066	572	759
41	General Plant	7,373,755	695,345	923,194
42	Total Gross Plant in Service	7,391,098	696,981	925,365
43	Less:			
44	Accumulated Depreciation	2,027,919	191,233	253,895
45		5,363,179	505,748	671,470
46	Less:			
47	Deferred Income Tax	29,186,404	2,752,278	3,654,138
48	Total Phoenix Office Allcoation (L9 - L10)	$ (23,823,225)	$ (2,246,530)	$ (2,982,668)

References:
See Company Schedule B-2 Appendix Page 5 of 5

ALLOWANCE FOR WORKING CAPITAL

LINE NO.	DESCRIPTION		(A) AMOUNT	(B) REFERENCE
1	Working Cash Requirement As Per Company	$	84,216	Company Schedule B-5, PG. 2 of 2
2	Working Cash Requirement As Per RUCO		(136,552)	RUCO Schedule JLK-6(1), L35
3	Adjustment	$	(220,768)	L2 - L1
4				
5	Material and Supplies Inventories As Per Company	$	26,083	Company Schedule B-5, PG. 2 of 2
6	Material and Supplies Inventories As Per RUCO		26,083	
7	Adjustment	$	-	L6 - L5
8				
9	Required Bank Balances As Per Company	$	99,566	Company Schedule B-5, PG. 2 of 2
10	Required Bank Balances As Per RUCO		99,566	
11	Adjustment	$	-	L10 - L9
12				
13	Prepayments & Special Deposits As Per Company	$	244,967	Company Schedule B-5, PG. 2 of 2
14	Prepayments & Special Deposits As Per RUCO		244,967	
15		$	-	L13 - L14
16				
17	TOTAL ADJUSTMENT (See RLM-2, Column (K))	$	(220,768)	Sum L3, L7, L11, L15

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RATE BASE ADJUSTMENT NO. 1 - PLANT ADJUSTMENTS
Summary of Post Test Year Plant Additions
Preliminary Costs vs Final Costs

Work Order Number	Account Description	Account Number	(A) Date const began.	(B) Date Construction is expected to be completed or was completed.	(C) Cost Per Company's Exhibit Sch B-2 Appendix Pages 1 thru 6	(D) Actual Cost 12/31/12 Per Company Response 1.3 (JMM 6-1)	(E) RUCO PLANT ADJUSTMENT VERDE VALLEY	(F) DEPRE RATE	(G) DEPRE ADJ
1-4921	Trans. & Dist. Plant	343	4/3/2012	5/25/2012	39,981	34,372	(5,609)	1.79%	(50)
1-4922	Source of Supply	314	9/7/2012	12/31/2012	50,000	224,204	(50,000)	3.13%	(783)
1-4924	Trans. & Dist. Plant	346	9/7/2012	12/31/2012	50,000	130,256	(50,000)	4.55%	(1,138)
1-4925	Pumping Plant	325	8/20/2012	12/31/2012	40,000	24,595	(40,000)	2.86%	(572)
1-4926	General Plant	397	4/24/2012	12/31/2012	147,891	178,138	(147,891)	6.67%	(4,932)
1-4920	General Plant	397	9/7/2012	12/31/2012	70,000	74,286	(70,000)	6.67%	(2,335)
1-4923	Water Treat. Plant (Land)	330	8/29/2012	12/31/2012	50,000	39,609	(50,000)	0.00%	-
1-4927	Trans. & Dist. Plant	343,345	4827/12	7/5/2012	60,000	59,980	(60,000)	2.09%	(626)
	Plant Post Test Year Adjustments				$ 507,872	$ 765,440	$ (473,500)		$ (10,434)
	Phoenix Office Adjustments	391/394	1/15/2012	2/7/2012	$ 237,841	$ 236,555	$ (121)	GP	(86)
	TOTAL POST TEST YEAR ADJUSTMENTS						$ (473,621)		$ (10,520)

NOTES:

(1) Work Orders completed after June 30, 2012 adjusted downward in total.
(2) Work Orders completed prior to June 30, 2012 adjusted based on actual costs versus budgeted costs. Column (D) less Column (C)

ADJUSTMENTS AS FOLLOWS:

Source of Supply	$ (50,000)	$ (783)
Pumping Plant	(40,000)	(572)
Water Treatment Equipment	(50,000)	-
Transmission & Distribution Plant	(115,609)	(1,813)
General Plant	(218,012)	(7,352)
	$ (473,621)	$ (10,520)

References:

Columns (A), (B) and (C'): Company Schedules B-2 Appendix pages 1 through 5
Column (D): Company Response to Data Request

EXPLANATION OF RATE BASE ADJUSTMENT NO. 2 - WORKING CAPITAL

Line No.		(A) Company Test Year Adjusted Results	(B) RUCO Adj	(C) RUCO Adjusted Results	(D) Revenue Lag Days1	(E) Expense Lag Days2	(F) Net Lag Days [D - E]	(G) Lead / Lag Factor [F ÷ 365]	(H) Working Cash Requirement [A X G]
1									
2	Operating Expenses								
3	Purchased Power	$ 262,792		$ 262,792	29.23	30.87	(1.64)	(0.0045)	$ (1,181)
4	Payroll	930,148		930,148	29.23	14.00	15.23	0.0417	38,811
5	Purchased Water	610		610	29.23	30.47	(1.24)	(0.0034)	(2)
6	Chemicals	17,436		17,436	29.23	(18.11)	47.34	0.1297	2,261
7	Property & Liability Insurance	49,336		49,336	29.23	(45.27)	74.50	0.2041	10,070
8	Workman's Compensation Insurance	9,176		9,176	29.23	(46.50)	75.73	0.2075	1,904
9	Health Insurance	177,978		177,978	29.23	(8.92)	38.15	0.1045	18,602
10	Other O&M (Excluding Rate Case Expense)	587,449	(29,834)	557,615	29.23	(9.27)	38.50	0.1055	58,817
11	Federal Income Taxes	294,536	(83,408)	211,128	29.23	37.00	(7.77)	(0.0213)	(4,494)
12	State Income Taxes	64,884	(18,374)	46,510	29.23	37.00	(7.77)	(0.0213)	(990)
13	FICA Taxes	69,483		69,483	29.23	14.00	15.23	0.0417	2,899
14	FUTA & SUTA Taxes	2,230		2,230	29.23	83.10	(53.87)	(0.1476)	(329)
15	Property Taxes	128,416	(2,320)	126,096	29.23	212.00	(182.77)	(0.5007)	(63,141)
16	Registration, Svc. Contracts, & Misc. Fees	64,052		64,052	29.23	(98.83)	128.06	0.3508	22,473
17	Retirement Annuities (401k)	84,555		84,555	29.23	34.72	(5.49)	(0.0150)	(1,272)
18									
19									
20	Subtotal	2,743,081	(133,937)	2,609,144					84,428
21									
22	Interest Expense	331,096	(22,846)	308,250	29.53	91.25	(61.72)	(0.1691)	(52,124)
23									
24	Total								$ (136,552)

Columns (A), (D), and (E) Company Schs. B-5 Appendix page 1
Column (B) RUCO Schs. JLK-7, JLK-8

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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	$ 3,065,721	$ 68,751	$ 3,134,472	-	$ 3,134,472
2	Commercial	459,140	-	459,140		459,140
3	Industrial	532	-	532		532
4	Private Fire Service	14,767	-	14,767		14,767
5	Other Water Revenues	12,480	-	12,480		12,480
6	Total Water Revenues	$ 3,552,640	$ 68,751	$ 3,621,391	$ 361,659	$ 3,983,050
7						
8	Miscellaneous	$ 42,441	$ -	$ 42,441	-	$ 42,441
9	Total Operating Revenues	$ 3,595,081	$ 68,751	$ 3,663,832	$ 361,659	$ 4,025,491
10						
11	Operating Expenses					
12	Source of Supply Expenses:					
13	Purchased Water	$ 610	$ -	$ 610		$ 610
14	Other	38,862	1,279	40,141		40,141
15	Pumping Expenses:					
16	Purchased Power	262,792	-	262,792		262,792
17	Purchased Gas	451	-	451		451
18	Other	94,464	11,394	105,858		105,858
19	Water Treatment Expenses	73,577	2,543	76,120		76,120
20	Transmission & Distribution Expenses	530,436	(40,152)	490,284		490,284
21	Customer Accounting Expenses	520,456	(20)	520,436		520,436
22	Sales Expense	881	-	881		881
23	Administrative & General Expenses	724,240	(23,622)	700,618		700,618
24	Total Operations & Maintenance Expense	$ 2,246,769	$ (48,577)	$ 2,198,192	$ -	$ 2,198,192
25						
26	Depreciation & Amortization Expenses	$ 672,841	$ (10,434)	$ 662,407		$ 662,407
27						
28	Taxes					
29	Federal Income Taxes	$ 51,093	$ 44,572	$ 95,665	115,463	$ 211,128
30	State Income Taxes	11,255	10,334	21,589	24,920	46,510
31	Property Taxes	119,773	2,306	122,079	4,017	126,096
32	Other	63,073	-	63,073		63,073
33	Total Taxes	$ 245,194	$ 57,212	$ 302,406	$ 144,400	$ 446,806
34						
35	Total Operating Expenses	$ 3,164,804	$ (1,800)	$ 3,163,004	$ 144,400	$ 3,307,405
36	Operating Income	$ 430,277	$ 70,551	$ 500,828	$ 219,596	$ 720,424

References:
Column (A): JLK-8, Col. A
Column (B): JLK-8, Col. K
Column (C): Col. A + Col.B
Column (D): JLK-1, JLK-1(2), JLK-15
Column (E): Col.C + Col.D

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SCHEDULE OF OPERATING INCOME - TEST YEAR WITH RUCO ADJUSTMENTS

Line No.		[A] Test Year Ended 12/31/2011	(B) Adjustment Normalize Maintneance IS - 1	(C) Adjustment Rate Case Expense IS - 2	(D) Adjustment Fleet Fuel Expense IS - 3	(E) Adjustment Misc Expenses IS - 4	(F) Adjustment Depreciation Expense IS - 5	(G) Adjustment Declining Usage IS - 6	(H) Adjustment LEFT BLANK	(I) Adjustment Property Tax IS - 7	(J) Adjustment Income Tax IS - 8	(K) Total Pro Forma Adjustments	(L) Test Year Adjusted Results
									-				
1	Operating Revenues												
2	Residential	$ 3,065,721						$ 68,751				$ 68,751	$ 3,134,472
3	Commercial	459,140										-	459,140
4	Industrial	532										-	532
5	Private Fire Service	14,767										-	14,767
6	Other Water Revenues	12,480										-	12,480
7	Total Water Revenues (L2 thru L6)	$ 3,552,640	$ -	$ -	$ -	$ -	$ -	$ 68,751	$ -	$ -	$ -	$ 68,751	$ 3,621,391
8													
9	Miscellaneous	42,441										-	42,441
10	Total Operating Revenues (L7 + L9)	$ 3,595,081	$ -	$ -	$ -	$ -	$ -	$ 68,751	$ -	$ -	$ -	$ 68,751	$ 3,663,832
11													
12	Operating Expenses												
13	Source of Supply Expenses:												
14	Purchased Water	610										$ -	610
15	Other	38,862			(2)			1,281				1,279	40,141
16	Pumping Expenses:	-										-	-
17	Purchased Power	262,792										-	262,792
18	Purchased Gas	451										-	451
19	Other	94,464			(24)			11,418				11,394	105,858
20	Water Treatment Expenses	73,577			(7)			2,550				2,543	76,120
21	Transmission & Distribution Expenses	530,436	(40,077)		(75)							(40,152)	490,284
22	Customer Accounting Expenses	520,456			(20)							(20)	520,436
23	Sales Expense	881										-	881
24	Administrative & General Expenses	724,240		(18,743)	(7)	(4,872)						(23,622)	700,618
25	Total Operations & Maint. Exp (L14 thru L24)	$ 2,246,769	$ (40,077)	$ (18,743)	$ (134)	$ (4,872)	$ -	$ 15,249	$ -	$ -	$ -	$ (48,577)	$ 2,198,192
26													
27	Depreciation & Amortization Expenses	672,841	-	-	-	-	(10,434)	-	-	-	-	(10,434)	662,407
28													
29	Taxes												
30	Federal Income Taxes	51,093									44,572	44,572	95,665
31	State Income Taxes	11,255									10,334	10,334	21,589
32	Property Taxes	119,773								2,306	-	2,306	122,079
33	Other	63,073								-		-	63,073
34	Total Taxes (L30 thru L33)	$ 245,194	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,306	$ 54,906	$ 57,212	$ 302,406
35													
36	Total Operating Expenses (L25 + L27 + L34)	$ 3,164,804	$ (40,077)	$ (18,743)	$ (134)	$ (4,872)	$ (10,434)	$ 15,249	$ -	$ 2,306	$ 54,906	$ (1,800)	$ 3,163,004
37	Operating Income (L10 less L36)	$ 430,277	$ 40,077	$ 18,743	$ 134	$ 4,872	$ 10,434	$ 53,502	$ -	$ (2,306)	$ (54,906)	$ 70,551	$ 500,828

References:
Column A, JLK-9
Column B, JLK-10
Column C, JLK-11
Column D, JLK-12
Column E, JLK-13
Column F, JLK-14
Column J, JLK-16

SCHEDULE OF OPERATING INCOME-TEST YR COMPANY ADJUSTMENTS

Line No.		[A] Test Year Ended 12/31/2011	(B) Adjustment Sales Tax IS - 1	[C] Adjustment Net Unbilled IS - 2	[D] Adjustment MAP IS - 3	(E) Adjustment ACRM IS - 4	(F) Adjustment Misc IS - 5	(G) Annualize YE Customers IS - 6	(H) Adjustment Weather IS - 7	(I) Adjustment Payroll IS - 8	(J) Adjustment Annualize Insurance IS - 9	(K) Adjustment Interest on Cust. Deposits IS - 10	(L) Adjustment Normalize Rents IS - 11	(M) Adjustment Adjust Purchase Water & Gas Exp IS - 12	(N) Adjustment Rate Case Expense IS - 13
1	Operating Revenues														
2	Residential	$ 3,355,969	$ (245,642)	$ 8,179	$ (2,678)	$ -	-	$ 18,644	$ (68,751)						
3	Commercial	485,813	(38,755)	1,269	(72)	-	-	10,885							
4	Industrial	374	(44)	202	-	-	-								
5	Private Fire Service	15,974	(1,207)				-								
6	Other Water Revenues	13,498	(1,018)		-	-	-								
7	Total Water Revenues (L2 thru L6)	$ 3,871,628	$ (286,666)	$ 9,650	$ (2,750)	$ -	$ -	$ 29,529	$ (68,751)	$ -	$ -	$ -	$ -	$ -	$ -
8															
9	Miscellaneous	45,656	(3,215)		-	-									
10	Total Operating Revenues (L7 + L9)	$ 3,917,284	$ (289,881)	$ 9,650	$ (2,750)	$ -	$ -	$ 29,529	$ (68,751)	$ -	$ -	$ -	$ -	$ -	$ -
11															
12	Operating Expenses														
13	Source of Supply Expenses:														
14	Purchased Water	610													
15	Other	37,983						361	(1,281)	1,773					
16	Pumping Expenses:														
17	Purchased Power	262,792													
18	Purchased Gas	451													
19	Other	80,858						3,216	(11,418)	2,905				18,603	
20	Water Treatment Expenses	76,861			(2,810)			718	(2,550)	1,277					
21	Transmission & Distribution Expenses	441,848						3,130		15,798				-	
22	Customer Accounting Expenses	478,844						3,392		20,500			15,988	459	
23	Sales Expense	881													
24	Administrative & General Expenses	609,622						4,318		19,020	24,253	1,261	676		46,256
25	Total Operations & Maint. Exp (L14 thru L24)	$ 1,990,750	$ -	$ -	$ (2,810)	$ -	$ -	$ 15,135	$ (15,249)	$ 61,273	$ 24,253	$ 1,261	$ 16,664	$ 19,062	$ 46,256
26															
27	Depreciation & Amortization Expenses	643,577													
28															
29	Taxes														
30	Federal Income Taxes	197,278													
31	State Income Taxes	29,304													
32	Property Taxes	135,561													
33	Other	345,481	(289,881)							7,473					
34	Total Taxes (L30 thru L33)	$ 707,624	$ (289,881)	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,473	$ -	$ -	$ -	$ -	$ -
35															
36	Total Operating Expenses (L25 + L27 + L34)	$ 3,341,951	$ (289,881)	$ -	$ (2,810)	$ -	$ -	$ 15,135	$ (15,249)	$ 68,746	$ 24,253	$ 1,261	$ 16,664	$ 19,062	$ 46,256
37	Operating Income (L10 less L36)	$ 575,333	$ -	$ 9,650	$ 60	$ -	$ -	$ 14,394	$ (53,502)	$ (68,746)	$ (24,253)	$ (1,261)	$ (16,664)	$ (19,062)	$ (46,256)

Columns (A) through columns (X) see Company Exhibit Schedule C-2

Columns (A) through columns (X) see (

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Verde Valley (Sedona, Pinewood, Rimrock)
Schedule JLK-9
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SCHEDULE OF OPERATING INCOME-TEST YR COMPANY ADJUSTMENTS

Line No.		(O) Adjustment Adjust A&G for BMP IS - 14	(P) Adjustment Fleet Fuel Expense IS -15	(Q) Adjustment Arsenic Treatmetn Exp IS - 16	(R) Adjustment Reflect New Vehicles IS - 17	(S) Adjustment Postage Expense (IS - 18	(T) Normalize T&D Maintenance IS - 19	(U) Adjustment Depreciation Expense IS - 20	(V) Adjustment Synchronise Interest Exp. IS - 21	(X) Adjustment Remove Other IS - 22	(Y) Adjustment Property Tax IS - 23	(Z) Adjustment Income Tax IS - 24	(AA) Total Pro Forma Adjustments	(BB) Test Year Adjusted Results
1	Operating Revenues													
2	Residential												(290,248)	$ 3,065,721
3	Commercial												(26,673)	459,140
4	Industrial												158	532
5	Private Fire Service												(1,207)	14,767
6	Other Water Revenues												(1,018)	12,480
7	Total Water Revenues (L2 thru L6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (318,988)	$ 3,552,640
8													-	
9	Miscellaneous												(3,215)	42,441
10	Total Operating Revenues (L7 + L9)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (322,203)	$ 3,595,081
11													-	
12	Operating Expenses												-	
13	Source of Supply Expenses:												-	
14	Purchased Water												-	610
15	Other		26		-								879	38,862
16	Pumping Expenses:												-	-
17	Purchased Power												-	262,792
18	Purchased Gas												-	451
19	Other		300		-								13,606	94,464
20	Water Treatment Expenses		81	-	-								(3,284)	73,577
21	Transmission & Distribution Expenses		924		-		68,736						88,588	530,436
22	Customer Accounting Expenses		247		-	1,026							41,612	520,456
23	Sales Expense												-	881
24	Administrative & General Expenses	18,750	84		-								114,618	724,240
25	Total Operations & Maint. Exp (L14 thru L24)	$ 18,750	$ 1,662	$ -	$ -	$ 1,026	$ 68,736	$ -	$ -	$ -	$ -	$ -	$ 256,019	$ 2,246,769
26													-	
27	Depreciation & Amortization Expenses							29,264					29,264	672,841
28													-	
29	Taxes												-	
30	Federal Income Taxes											(146,185)	(146,185)	51,093
31	State Income Taxes											(18,049)	(18,049)	11,255
32	Property Taxes										(15,788)		(15,788)	119,773
33	Other												(282,408)	63,073
34	Total Taxes (L30 thru L33)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (15,788)	$ (164,234)	$ (462,430)	$ 245,194
35													-	
36	Total Operating Expenses (L25 + L27 + L34)	$ 18,750	$ 1,662	$ -	$ -	$ 1,026	$ 68,736	$ 29,264	$ -	$ -	$ (15,788)	$ (164,234)	$ (177,147)	$ 3,164,804
37	Operating Income (L10 less L36)	$ (18,750)	$ (1,662)	$ -	$ -	$ (1,026)	$ (68,736)	$ (29,264)	$ -	$ -	$ 15,788	$ 164,234	$ (145,056)	$ 430,277

:ompany Exhibit Schedule C-2

OPERATING INCOME ADJUSTMENT NO. 1
TRANSMISSION & DISTRIBUTION MAINTENANCE EXPENSE

	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
Transmission & Distribution Adjustment	$ 68,736	$ (40,077)	$ 28,659

Calculation of Average T&D Expense
Years 2009, 2010, 2011

	2009	2001	2011
T&D Expense for years shown	$ 189,294	$ 161,385	$ 132,351
Sum Total for three year period	$ 483,030		
Average T&D for three year period		$ 161,010	
Test Year Transmission & Distribution Expense		132,351	
RUCO T&D Proposed T&D Expense Normalized		$ 28,659	

References
Column (A) See Company Schedule C-2 page 28

OPERATING INCOME ADJUSTMENT NO. 2
RATE CASE EXPENSE ADJUSTMENT

Line No.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total for Northern Group	$ 441,576	$ (158,185)	$ 283,391
2				
3	Allocation Factor (L33)			46.30%
4				
5	Navajo (Lakeside & Overgaard)			$ 131,200
6				
7	Amortization Period - 3 years			3
8				
9	RUCO Adjusted Rate Case Expense (L5 / L7)			$ 43,733
10				
11	Company Rate Case Expense as Filed (Company Sch. C-2 Appendix)			$ 62,476
12				
13	RUCO Pro Forma Rate Case Expense (L9 - L11)			$ (18,743)
14				
15	RUCO Adjustment			$ (18,743)
16				
17				
18	RUCO's Rate Base Expense Adjustment Calculation:			
19	Decision No. 64282, dated December 28, 2001, approved amount			
20	$216,892 for Arizona Water Company's Northern Group.		$ 216,892	
21				
22	Inflation Factor from January 1, 2002 through September 30, 2012			
23	Per Inflation Data.com		30.66%	
24				
25	Reasonable Amount of Rate Case Expense based on			
26	Decision No. 64282.		$ 283,391	
27				
28	RUCO Adjustment (Col. (A) Ln 1 - Col. (B) L 26)		$ 158,185	
29				
30				
31				
32	Allocation Factor Based on Number of Customers		Customers	Percent of Total
33	Verde Valley (Sedona, Pinewood, Rimrock)		10,564	53.70%

OPERATING INCOME ADJUSTMENT NO. 3
Fleet Fuel Expense Adjustment

Line No.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO CALCUALTED COST	(C) RUCO ADJUSTMENT AS RECOMM'D
1	Number of fuel gallons used in test year (Total Company)	190,584	190,584	190,584
2				
3	Price per gallon of fuel (Obtained from U.S. Energy Info Admin)	$ 3.5530	$ 3.4680	$ 0.0850
4				
5	Adjusted due to reduced price per gallon of fuel (Total Co)	$ 677,144	$ 660,945	$ 16,200
6				
7				
8	Percentage allocated to Navajo based on			
9	three factor allocation formula.	$ 63,855	$ 62,327	$ 1,528
10				
11				
12			RUCO	
13	**Verde Valley**	COMPANY	CALCUALTED	RUCO ADJUSTMENT
14	**ALLOCATED TO OPERATING DEPARTMENTS:**	AS FILED	COST	BY DEPARTMENT
15	Source of Supply Expenses:	$ 26	$ 24	$ (2)
16	Pumping Expenses	300	276	(24)
17	Water Treatment Expenses	81	74	(7)
18	Transmission & Distribution Expenses	924	849	(75)
19	Customer Accounting Expenses	247	227	(20)
20	Administrative & General Expenses	84	77	(7)
21				
22	Totals By Department	$ 1,662	$ 1,528	$ (134)
23				
24				
25	**GASOLINE PRICES PROJECTED FOR YEAR 2013**			
26	First Quarter $ 3.39			
27	Second Quarter 3.58			
28	Third Quarter 3.59			
29	Fourth Quarter 3.31			
30	Total for Year $ 13.87	Average by Quarter	$ 3.4680	

References:

Column (A) Provided in AWC data response RUCO
Gasoline Prices by Quarter from Priceline Gas Price Forecasts

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OPERATING INCOME ADJUSTMENT NO. 4
MISCELLANEOUS EXPENSE

Line	Account	Date	Vendor	Amount	Description	Verde Valley 111 Dues	Verde Valley 111 Flowers	Verde Valley 111 Other	Navajo 081 Dues	Navajo 081 Flowers	Navajo 081 Other	Phoenix Office 300 Dues	Phoenix Office 300 Flowers	Phoenix Office 300 Other
1	081-93000-0000	4/27/2011	HEBER-OVERGAARD CHAMBER OF COMM	$ 70	MEMBERSHIP DUES									
2	081-93000-0000	6/8/2011	PINETOP-LAKESIDE CHAMBER OF COMMERCE	305	MEMBERSHIP DUES				$ 70					
3	081-93000-0000	3/17/2011	ARIZONA WATER FESTIVALS	300	SPONSORSHIPS				305					
4	081-93000-0000	5/19/2011	BRHS JUSTIN FLORES BENEFIT TOURNAMENT	500	SPONSORSHIPS						300			
5	081-92610-0000	9/16/2011	DOROTHYS FLOWERS & FINE ARTS	87	GIFTS & AWARDS						500			
6	081-92610-0000	3/30/2011	FLOWERS BY KARMA	89	GIFTS & AWARDS					87				
7	081-93000-0000	12/9/2011	FIESTA MEXICANA RESTAURANT	300	CHRISTMAS LUNCHEON					89				
8											300			
9	111-93000-0000	8/8/2011	SEDONA CANYON CHAMBER COMMERCE	450	MEMBERSHIP DUES	450								
10														
11	300-90100-0000	1/1/2011	ARIZONA CHAMBER OF COMMERCE	220	MEMBERSHIP DUES									
12	300-90100-0000	1/19/2011	ARIZONA INVESTMENT COUNCIL	329	MEMBERSHIP DUES							220		
13	300-92100-0000	5/25/2011	ARIZONA TOWN HALL	22	MEMBERSHIP DUES							329		
14	300-90100-0000	4/20/2011	WATER UTILITY ASSOC OF ARIZONA	1,317	MEMBERSHIP DUES							22		
15	300-92610-0000	1/31/2011	PHOENIX FLOWER SHOPS	25	GIFTS & AWARDS							1,317		
16	300-92610-0000	3/31/2011	PHOENIX FLOWER SHOPS	13	GIFTS & AWARDS								25	
17	300-92610-0000	7/21/2011	PHOENIX FLOWER SHOPS	35	GIFTS & AWARDS								13	
18	300-92610-0000	8/31/2011	PHOENIX FLOWER SHOPS	53	GIFTS & AWARDS								35	
19	300-93000-0000	2/28/2011	PHOENIX FLOWER SHOPS	22	GIFTS & AWARDS								53	
20	300-93000-0000	3/31/2011	PHOENIX FLOWER SHOPS	33	GIFTS & AWARDS								22	
21	300-92610-0000	12/31/2011	TERRYBERRY MANUFACTURING JEWELERS	21	GIFTS & AWARDS								33	
22	300-92610-0000	12/31/2011	TERRYBERRY MANUFACTURING JEWELERS	838	GIFTS & AWARDS									
23	300-90100-0000	6/14/2011	WATER UTILITY ASSOC OF ARIZONA	110	LUNCHEONS									21
24	300-90100-0000	11/9/2011	WATER UTILITY ASSOC OF ARIZONA	220	LUNCHEONS									838
25	300-92610-0000	4/30/2011	BW PLUS DOBSON RANCH INN	605	LUNCHEONS									110
26	300-92610-0000	3/17/2011	ALBERTSON'S LLC	107	EMPLOYEE PICNIC									220
27	300-92610-0000	8/31/2011	ARIZONA GOLF RESORT	445	AWARDS BANQUET									605
28	300-92610-0000	10/13/2011	CITRON SOUND SERVICES	67	AWARDS BANQUET									107
29	300-92610-0000	12/9/2011	CITRON SOUND SERVICES	132	AWARDS BANQUET									445
30	300-92610-0000	12/31/2011	CITRON SOUND SERVICES	22	AWARDS BANQUET									67
31	300-92610-0000	2/14/2011	PICNIC SPECIALTIES INC	494	EMPLOYEE PICNIC									132
32	300-92610-0000	2/14/2011	PICNIC SPECIALTIES INC	334	EMPLOYEE PICNIC									22
33	300-92610-0000	3/22/2011	POINTE HILTON SQUAW PEAK	3,406	AWARDS BANQUET									494
34														334 3,406
35	Administration Expenses to be Adjusted			$ 10,971		$ 450	$ -	$ -	$ 375	$ 176	$ 1,100	$ 1,888	$ 181	$ 6,801
36	Membership Dues Adjusted at 50 Percent			$ 1,356		$ 225			$ 188			$ 944		
37	Administration Expenses After Adjustment			$ 9,615		$ 225	$ -	$ -	$ 188	$ 176	$ 1,100	$ 944	$ 181	$ 6,801
38	Phoenix Office Allocation	Navajo - 43%							$ 406	$ 78	$ 2,924	$ (406)	$ (78)	$ (2,924)
39		Verde Valley - 57%				$ 538	$ 103	$ 3,877				(538)	(103)	(3,877)
40														
41	Final Adjustment for Administration Expenses			$ 9,615		$ 763	$ 103	$ 3,877	$ 593	$ 254	$ 4,024	$ -	$ -	$ -
42														

Line		
43	Verde Valley	$ 4,743
44	Navajo	$ 4,872
		$ 9,615

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OPERATING INCOME ADJUSTMENT NO. 5
CALCULATION OF DEPRECIATION EXPENSE

Line No.	Acct. No.		Present Depreciation Rates	(A) Plant Balance Per GL	(B) Depre Exp Prior to Adjustments	(C) Depre Exp Post Test Year Plant Prior to Adjustments	(D) Depre Exp Phoenix Off Prior to Adjustments	(E) Depre Exp Meter Shop Prior to Adjustments	(F) Depre Exp As Filed By Company	(G) RUCO Depre Adjustments Post Test Yr Plant	(H) RUCO FINAL Depre Expense
1		Intangible Plant									
2	301	Organization	0.00%	-	-	-	-	-	-	-	-
3	302	Franchises	See Acct. 111	-	-	-	-	-	-	-	-
4	303	Other Intangibles	See Acct. 111	1,946	97	-	40	-	137	-	137
5		Subtotal Intangible Plant		1,946	97	-	40		137	-	137
6		Source of Supply Plant									
7	310.1	Water Rights	0.00%	500,739	-	-	-	-	-	-	-
8	310.3	Other Source of Supply Land	0.00%	30,155	-	-	-	-	-	-	-
9	310.4	Wells - Other	See Acct. 111	-	-	-	-	-	-	-	-
10	314	Wells	3.13%	1,758,846	55,052	1,565	-	-	56,617	-	56,617
11		Subtotal Source of Supply Plant		2,289,740	55,052	1,565	-	-	56,617	-	56,617
12		Pumping Plant									
13	320	Pumping Plant Land	0.00%	8,553	-	-	-	-	-	-	-
14	321	Pumping Plant Structures & Improvements	2.86%	149,931	4,288	-	-	-	4,288	-	4,288
15	325	Electtric Pumping Equipment	5.88%	2,732,041	160,644	2,352	-	-	162,996	-	162,996
16	328	Gas Engine Equipment	4.00%	-	-	-	-	-	-	-	-
17		Subtotal Pumping Plant		2,890,525	164,932	2,352	-	-	167,284	-	167,284
18		Water Treatment Plant									
19	330	Water Treatment Plant Land	0.00%	-	-	-	-	-	-	-	-
20	331	Water Treatment Structures & Improvements	2.50%	563	14	-	-	-	14	-	14
21	332	Water Treatment Equipment	2.86%	147,800	4,227	-	-	6	4,233	(2,542)	1,691
22		Subtotal Water Treatment Plant		148,363	4,241	-	-	6	4,247	(2,542)	1,705
23		Transmission & Distribution Plant									
24	340	Transmission and Distribution Land	0.00%	53,126	-	-	-	-	-	-	-
25	342	Storage Tanks	2.00%	1,338,226	26,765	-	-	-	26,765	-	26,765
26	343	Transmission & Distribution Mains	1.79%	14,098,390	252,361	1,781	-	10	254,152	(4,932)	249,220
27	344	Fire Sprinkler Taps	2.00%	204,862	4,097	-	-	-	4,097	-	4,097
28	345	Services	2.38%	4,978,068	118,478	12	-	-	118,490	(2,960)	115,530
29	346	Meters	4.55%	574,011	26,118	2,275	-	-	28,393	-	28,393
30	348	Hydrants	1.82%	1,407,748	25,621	-	-	-	25,621	-	25,621
31		Subtotal Transmission & Distribution Plant		22,654,431	453,439	4,068	-	-	457,517	(7,892)	449,625
32		General Plant									
33	389	General Plant Land	0.00%	1,995	-	-	-	-	-	-	-
34	390	General Plant Structures	2.50%	323,670	8,092	-	128	125	8,345	-	8,345
35	390.1	Leasehold Improvements	See Acct. 108.2	74,227	13,259	-	4,531	-	17,790	-	17,790
36	391	Office Furniture & Equipment	6.67%	219,044	14,610	-	32,461	70	47,141	-	47,141
37	393	Warehouse Equipment	5.00%	3,512	176	-	17	36	229	-	229
38	394	Tools, Shop & Garage Equipment	4.00%	110,115	4,405	-	929	262	5,596	-	5,596
39	395	Laboratory Equipment	5.00%	2,690	135	-	7	14	156	-	156
40	396	Power Operated Equipment	6.67%	10,462	698	-	-	9	707	-	707
41	397	Communication Equipment	6.67%	250,792	16,728	14,533	1,328	-	32,589	-	32,589
42	398	Miscellaneous Equipment	3.33%	37,015	1,233		23	-	1,256	-	1,256
43		Subtotal General Plant		1,033,522	59,334	14,533	39,424	516	113,807	-	113,807
44		Plant in Service		$ 29,018,527	$ 737,095	$ 22,518	$ 39,464	$ 522	$ 799,609	$ (10,434)	
45		Total Depreciation Test Year Adjusted: Col (F) Ln 44 + Col G Ln 44									$ 789,175
46		Less: Amortization of Contribution in Aid of Construction			2%	$ 6,338,426					$ (126,769)
47		Pro Forma Depreciation Expense: Col (H) Ln 45 + Ln 46									$ 662,407
48		Depreciation Expense as Filed by Company - Test Year Adjusted									$ 672,841
49		**RUCO Adjustment to Depreciation Expense and Accumulated Depreciation**									$ (10,434)

References

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OPERATING INCOME ADJUSTMENT NO. 6
DECLINING USAGE

DESCRIPTION	(A) COMPANY ESTIMATE	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
Residential Revenues - Reductions	$ (68,751)	$ 68,751	$ -
REVENUE REDUCTIONS	$ (68,751)	$ 68,751	$ -
Operating Expense Reductions			
Source of Supply - Other	$ (1,281)	$ 1,281	$ -
Pumping Expense - Other	(11,418)	$ 11,418	-
Water Treatment Expense	(2,550)	$ 2,550	-
OPERATING EXP. REDUCTIONS	$ (15,249)	$ 15,249	$ -

RUCO is taking the position that AWC's downward adjustment in revenues and expenses based on "calculated" reductions in usage is not a known and measurable change and is therefore not an appropriate adjustment in net operating expenses.

References:
Column (A) See Company Schedule C-2

OPERATING INCOME ADJUSTMENT NO. 7
PROPERTY TAXES

LINE NO.	Property Tax Calculation	(A) RUCO AS ADJUSTED		(B) RUCO RECOMMENDED	
1	RUCO Adjusted Test Year Revenues - JLK-6	$	3,663,832	$	3,663,832
2	Multiplied by 2		2		2
3	Subtotal (Line 1 * Line 2)	$	7,327,664	$	7,327,664
4	RUCO Adjusted Test Year Revenues - 2011		3,663,832		
5	RUCO Recommended Revenue, Per Schedule JLK-1				4,025,491
6	Subtotal (Line 4 + Line 5)	$	10,991,496	$	11,353,155
7	Number of Years		3		3
8	Three Year Average (Line 5 / Line 6)	$	3,663,832	$	3,784,385
9	Department of Revenue Mutilplier		2		2
10	Revenue Base Value (L8 X L9)	$	7,327,664	$	7,568,770
11	Plus: 10% of CWIP -		-		-
12	Less: Net Book Value of Licensed Vehicles		-		-
13	Full Cash Value (L10 + L11 + L12))	$	7,327,664	$	7,568,770
14	Assessment Ratio		20.0%		20.0%
15	Assessment Value (L13 X L14)	$	1,465,533	$	1,513,754
16	Composite Property Tax Rate (L19 / L15)		8.3300%		8.3300%
17					
18	RUCO Proposed Property Tax Expense (L15 X L16))	$	122,079		
19	Company Proposed Property Tax		119,773		
20					
21	RUCO Test Year Adjustment (L16 - L17)	$	2,306		
22	Property Tax - RUCO Recommended Revenue (L15 X L16)			$	126,096
23	RUCO Test Year Adjusted Property Tax Expense (L18)				122,079
24	Increase/(Decrease) to Property Tax Expense			$	4,017
25					
26	Increase/(Decrease) to Property Tax Expense			$	4,017
27	Increase in Revenue Requirement (L5 - L4)				361,659
28	Increase /(Decrease) to Property Tax per Dollar Increase in Revenue (L26 / L27)				**1.1107%**

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OPERATING INCOME ADJUSTMENT NO. 8
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(B) AMOUNT
1	Federal Income Taxes as Filed - See Company Schedule C-2 Page 9	$ 51,093
2		
3	RUCO Calculated Income Tax - See JLK - Schedule 1 Page 2 Ln 52	95,665
4		
5	RUCO Calculated Adjustment	$ 44,572

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COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO RECOMMENDED	(D) CAPITAL RATIO	(E) COST RATE	(F) WEIGHTED COST RATE
1	Long-Term Debt	$ 75,000,000	$ -	$ 75,000,000	48.95%	6.82%	3.34%
2							
3	Common Equity	78,221,194	-	78,221,194	51.05%	8.75%	4.47%
4							
5	Total Capitalization	$ 153,221,194	$ -	$ 153,221,194	100.00%		
6							
7							
8	WEIGHTED AVERAGE COST OF CAPITAL						7.81%

References:
Columns (A) Thru (F): WAR Testimony

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JLK-1	1 & 2	REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR
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JLK-3	1	SUMMARY ORIGINAL COST RATE BASE WITH ADJUSTMENTS
JLK-4	1 & 2	DIRECT PLANT AND ACCUMULATION DEPRECIATION
JLK-4 (1)	1	PHOENIX OFFICE AND METER SHOP PLANT ALLOCATION
JLK-5	1	ALLOWANCE FOR WORKING CAPITAL
JLK-6	1	RATE BASE ADJUSTMENT NO. 1 - PLANT ADJUSTMENTS
JLK-6(1)	1	RATE BASE ADJUSTMENT NO. 2 - WORKING CAPITAL
JLK-7	1	OPERATING INCOME
JLK-8	1 & 2	SCHEDULE OF OPERATING INCOME - TEST YEAR WITH RUCO ADJUSTMENTS
JLK-9	1 & 2	SCHEDULE OF OPERATING INCOME-TEST YEAR COMPANY ADJUSTMENTS
JLK-10	1	OPERATING INCOME ADJUSTMENT NO. 1 - TRANSMISSION & DISTRIBUTION EXPENSE NORMALIZATION
JLK-11	1	OPERATING INCOME ADJUSTMENT NO. 2 - RATE CASE EXPENSE
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JLK-15	1	OPERATING INCOME ADJUSTMENT NO. 6 - DECLINING USAGE
JLK-16	1	OPERATING INCOME ADJUSTMENT NO. 7 - PROPERTY TAXES
JLK-17	1	OPERATING INCOME ADJUSTMENT NO. 8 - INCOME TAXES
JLK-18	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	$	26,134,793	$	25,528,437
2					
3	Adjusted Operating Income (Loss)	$	1,134,775	$	1,185,321
4					
5	Current Rate of Return (L3 / L1)		4.34%		4.64%
6					
7	Required Operating Income (L9 X L1)	$	2,380,736	$	1,993,184
8					
9	Required Rate of Return on Fair Value Rate Base		9.11%		7.81%
10					
11	Operating Income Deficiency (L7 - L3)	$	1,245,961	$	807,863
12					
13	Gross Revenue Conversion Factor (JLK-1, Page 2 of 2)		1.6465		1.6465
14					
15	Required Increase in Gross Revenue Requirement (L11 X L13))	$	2,051,475	$	1,330,169
16					
17	Adjusted Test Year Revenue	$	6,529,576	$	6,592,779
18					
19	Proposed Annual Revenue (L15 + L17)	$	8,581,051	$	7,922,948
20					
21	Required Percentage Increase in Revenue (L15 / L17)		31.42%		20.18%
22					
23	Consolidated Revenue Adjustment	$	-	$	-
24					
25	Required Increase in Gross Revenue Under Proposed Consolidation	$	-	$	-
26					
27	Required Revenue Under Proposed Consolidation	$	-	$	-
28					
29	Required Percentage Increase in Revenue Under Proposed Consolidation		0%		0%
30					
31	Rate of Return on Common Equity		11.30%		8.75%

References:
Column (A): Company Schs. A-1 and C-1
Column (B): RUCO Schs. JLK-2, JLK-7, and JLK-18

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:			
1	Revenue	100.0000%		
2	Proposed Bad Debt Expense (Per Co. Workpapers)	-		
3	Subtotal (L1 thru L2)	100.0000%		
4	Combined Federal, State, Property Tax Rate (L22)	39.2661%		
5	Subtotal (L3 - L4)	60.7339%		
6	**Revenue Conversion Factor** (L1 / L5)	**1.6465**		
7				
8	***CALCULATION OF EFFECTIVE TAX RATE:***			
9	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%		
10	Arizona State Income Tax Rate	6.9680%		
11	Federal Taxable Income (L9 - L10)	93.0320%		
12	Applicable Federal Income Tax Rate (L58)	34.0000%		
13	Effective Federal Income Tax Rate (L11 X L12)	31.6309%		
14	Combined Federal and State Income Tax Rate (L10 + L13)	38.5989%		
15				
16	***CALCULATION OF EFFECTIVE PRPERTY TAX FACTOR:***			
17	Unity	100.0000%		
18	Combined Federal and State Tax Rate	38.5989%		
19	1 Minus Combined Income Tax Rate	61.4011%		
20	Property Tax Factor	1.0867%		
21	Effective Property Tax Factor (L19 x L 20)	0.6672%		
22	Combined Federal, State & Property Tax RateTax Rate (L14 + L21)	39.2661%		
23				
24	RUCO Required Operating Income (Sch. JLK-1, Col. (B), L7)	$ 1,993,184		
25	RUCO Adj'd T.Y. Oper'g Inc. (Loss) (Sch. JLK-1, Col. (B), L3)	1,185,321		
26	Required Increase In Operating Income (L24 - L25)		$ 807,863	
27				
28	Income Taxes On Recommended Revenue (Col. (C), L53)	$ 716,867		
29	Income Taxes On Test Year Revenue (Col. (C), L55)	209,016		
30	Required Increase In Revenue To Provide For Income Taxes (L28 - L29)		$ 507,851	
31				
32	Property Tax with Recommended Revenue (Sch. JLK-7, Col. E, L31)	229,379		
33	Propertry Tax on TestYear Revenue (Sch. JLK-7, Col. C, L31)	214,925		
34	Increase in Property Tax Due to Increase in Revenue (L32 - L33)		$ 14,454	
35				
36	Total Required Increase In Revenue (L26 + L30 + L34)		$ 1,330,169	
37			RUCO	
38	***RUCO's CALCULATION OF INCOME TAX:***		**Test Year**	**Recommended**
39	RUCO Revenue (Sch. JLK-1, Col. (B), L19)		$ 6,592,779	$ 7,922,948
40	**Less:**			
41	Operating Expense Excluding Income Tax (Sch. JLK-7, Col. (E), L24 + L26 + L31 + L32)		5,198,442	5,212,897
42	Synchronized Interest (Col. (C), L63)		852,829	852,829
43	Arizona Taxable Income (L39 - L41 - L42)		$ 541,508	$ 1,857,222
44	Arizona State Income Tax Rate		6.9680%	6.9680%
45	Arizona Income Tax (L43 X L44)		$ 37,732	$ 129,411
46	Fed. Taxable Income (L43 - L45)		$ 503,776	$ 1,727,811
47	Fed. Tax On 1st Inc. Bracket ($1 - $50,000) @ 15%		$ 7,500	$ 7,500
48	Fed. Tax On 2nd Inc. Bracket ($50,001 - $75,000) @ 25%		$ 6,250	$ 6,250
49	Fed. Tax On 3rd Inc. Bracket ($75,001 - $100,000) @ 34%		$ 8,500	$ 8,500
50	Fed. Tax On 4th Inc. Bracket ($100,001 - $335,000) @ 39%		$ 91,650	$ 91,650
51	Fed. Tax On 5th Inc. Bracket ($335,001 - $10M) @ 34%		$ 57,384	$ 473,556
52	Total Federal Income Tax (L47 thru L 51)		$ 171,284	$ 587,456
53	Combined Federal And State Income Tax (L45+ L52)		$ 209,016	$ 716,867
54				
55	Adjusted TY Combined Federal and State Income Tax (JLK-7, Col. (C), L29 and L30)			$ 209,016
56	RUCO Proposed Income Tax Adjustment (L53 - L55)			$ 507,851
57				
58	Applicable Federal Income Tax Rate			
59				
60	**NOTE (A): Interest Synchronization**			
61	Adjusted Rate Base JLK-2, Col. (C), L28			$ 25,528,437
62	Weighted Cost Of Debt JLK-18, Col. (F), L1			3.34%
63	Interest Expense (L61 X L62)			$ 852,829

SUMMARY RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO OCRB/FVRB ADJUSTMENTS	(C) RUCO ADJ'TED OCRB/FVRB
1	Plant Classification			
2	Intangible Plant	$ 4,518	$ -	$ 4,518
3	Source of Supply Plant	7,276,838	-	7,276,838
4	Pumping Plant	3,329,025	-	3,329,025
5	Water Treatment Plant	6,824,041	1,279	6,825,320
6	Transmission & Distribution Plant	34,572,451	(76,043)	34,496,408
7	General Plant	1,944,095	(164,453)	1,779,643
8	Total Gross Plant in Service (L2 thru L7)	$ 53,950,969	$ (239,216)	$ 53,711,753
9				
10	Accumulated Depreciation	$ 13,444,569	$ (6,159)	$ 13,438,410
11	Net Utility Plant In Service (L8 - L10)	$ 40,506,400	$ (233,057)	$ 40,273,343
12				
13	Advances In Aid Of Const.	$ 3,631,836	$ -	$ 3,631,836
14				
15	Contribution In Aid Of Const.	$ 10,153,446	$ -	$ 10,153,446
16	Accumulated Amortization Of CIAC	$ (2,484,339)	$ -	$ (2,484,339)
17	NET CIAC (L15 + L16)	$ 7,669,107	$ -	$ 7,669,107
18				
19	Deferred Income Tax	$ 3,654,138	$ -	$ 3,654,138
20				
21	Customer Deposits	$ 47,763	$ -	$ 47,763
22				
23	Allowance For Working Capital	$ 631,466	$ (373,297)	$ 258,169
24				
25	Net Regulatory Asset / (Liability)	$ -	$ -	$ -
26				
27	Adjustment to Match Rate Base with G/L	$ (232)	$ -	$ (232)
28	TOTAL RATE BASE (L11-L13-L17-L19-L21+L23+L25)	$ 26,134,791	$ (606,354)	$ 25,528,437

References:
Column (A): Company Schedule B-1 and JLK-3 Col. E
Column (B): Schedule JLK-3 Cols. G and H
Column (C): Col. A + Col. B; JLK-3

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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED NET PLANT TEST YEAR	(B) COMPANY ADJ NO 1 POST TEST YEAR ADJUSTMENTS	(C) COMPANY ADJ NO 2 PHOENIX OFF AND METER SHOP	(D) BLANK	(E) COMPANY AS FILED OCRB/FVRB	(F) RUCO ADJMT NO. 1 POST TEST YR ADJUSTMENTS	(G) RUCO ADJMT NO. 2 WORKING CAPITAL	(H) RUCO ADJ'TED OCRB/FVRB
1	Plant Classification								
2	Intangible Plant	$ 3,373	$ -	$ 1,145		$ 4,518	$ -	$ -	4,518
3	Source of Supply Plant	7,276,828	-	10		7,276,838	-	-	7,276,838
4	Pumping Plant	3,329,025		-		3,329,025	-	-	3,329,025
5	Water Treatment Plant	3,902,996	2,920,788	257		6,824,041	1,279	-	6,825,320
6	Transmission & Distribution Plant	34,115,731	455,961	759		34,572,451	(76,043)	-	34,496,408
7	General Plant	856,615	164,286	923,194		1,944,095	(164,453)	-	1,779,643
8	Total Gross Plant in Service (Sum L2 thru L7)	$ 49,484,568	$ 3,541,035	925,365		$ 53,950,969	$ (239,216)	$ -	$ 53,711,753
9									
10	Accumulated Depreciation	$ 13,138,571	52,103	253,895		$ 13,444,569	(6,159)	-	13,438,410
11	Net Utility Plant In Service (L8 less L10)	$ 36,345,998	$ 3,488,932	$ 671,470		$ 40,506,400	$ (233,057)	$ -	$ 40,273,343
12									
13	Advances In Aid Of Const.	$ 3,631,836	$ -	$ -		$ 3,631,836	$ -	$ -	3,631,836
14									
15	Contribution In Aid Of Const.	10,153,446	$ -	$ -		$ 10,153,446	$ -	$ -	10,153,446
16	Accumulated Amortization Of CIAC	(2,484,339)	-	-		$ (2,484,339)	-	-	(2,484,339)
17	NET CIAC (L15 less L16)	$ 7,669,107	$ -	$ -		$ 7,669,107		$ -	$ 7,669,107
18									
19	Deferred Income Tax	$ -	$ -	$ 3,654,138		$ 3,654,138	$ -	$ -	$ 3,654,138
20									
21	Customer Deposits	$ 47,763	$ -	$ -		$ 47,763	$ -	$ -	$ 47,763
22									
23	Allowance For Working Capital	$ 631,466	$ -	$ -		$ 631,466	$ -	$ (373,297)	$ 258,169
24									
25	Net Regulatory Asset / (Liability)	$ -	$ -			$ -	$ -	$ -	$ -
26									
27	Adjustment to Match Rate Base with G/L	$ (232)	$ -	$ -		$ (232)	$ -	$ -	$ (232)
28	TOTAL RATE BASE (Sum L's 11, 13, 17, 19, 21, 23, 25 27)	$ 25,628,526	$ 3,488,932	$ (2,982,668)		$ 26,134,791	$ (233,057)	$ (373,297)	$ 25,528,437

References:
Columns (A) through (E): Company Schedule B-2
Column (F): RUCO Schedule JLK-6, Col. E
Column (G): RUCO Schedule JLK-5, Col. A

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DIRECT PLANT AND ACCUMULATED DEPRECIATION

Line No.	Acct. No.		Depreciation Rate Dec. 64282 01/01/02 To 7/31/10	Depreciation Rate Dec. 71845 08/01/10 To Present	Starting Point for Plant Rec. 12/31/2007	2008 Additions	2008 Retirements	2008 Adjustments	2008 Depreciation Expense	2008 Balance	2009 Additions	2009 Retirements	2009 Adjustments	2009 Depreciation Expense	2009 Balance
1		Intangible Plant													
2	301	Organization	0.00%	0.00%	-	-	-	-	-	-	-	-	-	-	-
3	302	Franchises	See Acct. 11	See Acct. 111	935	-	-	-	-	935	-	-	-	-	935
4	303	Other Intangibles	See Acct. 11	See Acct. 111	2,438	-	-	-	159	2,438	-	-	-	159	2,438
5		Subtotal Intangible Plant			3,373	-	-	-	159	3,373	-	-	-	159	3,373
6		Source of Supply Plant													
7	310.1	Water Rights	0.00%	0.00%	131,388	24,176	-	-	-	155,564	605	-	-	-	156,169
8	310.3	Other Source of Supply Land	0.00%	0.00%	244,189	-	-	-	-	244,189	387,482	-	-	-	631,671
9	310.4	Wells - Other	See Acct. 11	See Acct. 111	-	-	-	-	-	-	-	-	-	-	-
10	314	Wells	2.59%	3.13%	6,872,064	-	-	-	177,986	6,872,064	-	(401,309)	-	172,789	6,470,755
11		*Subtotal Source of Supply Plant*			7,247,641	24,176	-	-	177,986	7,271,816	388,087	(401,309)	-	172,789	7,258,594
12		Pumping Plant													
13	320	Pumping Plant Land	0.00%	0.00%	5,544	-	-	-	-	5,544	-	-	-	-	5,544
14	321	Pumping Plant Structures & Improvements	2.59%	2.86%	115,330	647	(7,627)	-	2,897	108,350	-	-	-	2,806	108,350
15	325	Electtric Pumping Equipment	2.59%	5.88%	2,996,185	216,239	(186,330)	-	77,989	3,026,094	216,684	(74,896)	-	80,212	3,167,881
16	328	Gas Engine Equipment	2.59%	4.00%	223	-	-	-	6	223	-	-	-	6	223
17		Subtotal Pumping Plant			3,117,282	216,886	(193,957)	-	80,891	3,140,211	216,684	(74,896)	-	83,024	3,281,998
18		Water Treatment Plant													
19	330	Water Treatment Plant Land	0.00%	0.00%	-	-	-	-	-	-	-	-	-	-	-
20	331	Water Treatment Structures & Improvements	2.59%	2.50%	212,008	9,670	-	-	5,616	221,678	8,063	-	-	5,846	229,741
21	332	Water Treatment Equipment	2.59%	2.86%	983,169	1,044,644	-	-	38,992	2,027,813	-	(1,483)	(127,597)	50,849	1,898,733
22		Subtotal Water Treatment Plant			1,195,178	1,054,314	-	-	44,608	2,249,492	8,063	(1,483)	(127,597)	56,695	2,128,475
23		Transmission & Distribution Plant													
24	340	Transmission and Distribution Land	0.00%	0.00%	134,524	-	-	-	-	134,524	-	-	-	-	134,524
25	342	Storage Tanks	2.59%	2.00%	1,812,602	(34,448)	-	-	46,500	1,778,154	-	(3,891)	-	46,004	1,774,263
26	343	Transmission & Distribution Mains	2.59%	1.79%	18,974,430	1,501,078	(19,803)	-	510,620	20,455,705	2,700,042	(14,104)	(17,779)	564,355	23,123,864
27	344	Fire Sprinkler Taps	2.59%	2.00%	668,787	8,171	-	-	17,427	676,958	38,382	-	-	18,030	715,340
28	345	Services	2.59%	2.38%	4,361,199	327,241	(14,596)	-	117,004	4,673,844	153,696	(9,011)	-	122,926	4,818,529
29	346	Meters	2.59%	4.55%	788,090	26,334	(132)	-	20,751	814,292	1,533	(141)	-	21,108	815,684
30	348	Hydrants	2.59%	1.82%	1,636,216	11,047	(1,082)	-	42,507	1,646,181	2,833	(2,294)	-	42,643	1,646,720
31		Subtotal Transmission & Distribution Plant			28,375,848	1,839,423	(35,613)	-	754,810	30,179,658	2,896,486	(29,441)	(17,779)	815,067	33,028,924
32		General Plant													
33	389	General Plant Land	0.00%	0.00%	2,858	-	-	-	-	2,858	-	-	-	-	2,858
34	390	General Plant Structures	2.59%	2.50%	193,171	11,450	(2,691)	-	5,117	201,930	-	-	-	5,230	201,930
35	390.1	Leasehold Improvements	See Acct. 108	See Acct. 108.2	49,955	-	-	-	945	49,955	-	-	-	4	49,955
36	391	Office Furniture & Equipment	2.59%	6.67%	138,306	227	-	-	3,585	138,533	341	(266)	-	3,589	138,608
37	393	Warehouse Equipment	2.59%	5.00%	27,514	-	-	-	713	27,514	-	-	-	713	27,514
38	394	Tools, Shop & Garage Equipment	2.59%	4.00%	107,110	5,919	-	-	2,851	113,029	-	-	-	2,927	113,029
39	395	Laboratory Equipment	2.59%	5.00%	11,767	785	-	-	315	12,552	-	-	-	325	12,552
40	396	Power Operated Equipment	2.59%	6.67%	33,199	1,906	-	-	885	35,105	1,071	(710)	-	914	35,466
41	397	Communication Equipment	2.59%	6.67%	198,908	2,758	-	-	5,187	201,666	2,495	-	-	5,255	204,161
42	398	Miscellaneous Equipment	2.59%	3.33%	30,751	-	-	-	796	30,751	-	-	-	796	30,751
43		Subtotal General Plant			793,538	23,045	(2,691)	-	20,393	813,892	3,907	(976)	-	19,754	816,823
44		Plant in Service			$ 40,732,859	$ 3,157,844	$ (232,261)	$ -	$ 1,078,848	$ 43,658,442	$ 3,513,227	$ (508,105)	$ (145,376)	$ 1,147,488	$ 46,518,187
45															
46		Accumulated Depreciation & Amort.			$ 9,431,978				$ 10,278,565					$ 10,917,948	
47		Net Plant in Service			$ 31,300,881	$ 3,157,844	$ (232,261)	$ -		$ 43,658,442	$ 3,513,227	$ (508,105)	$ (145,376)		$ 46,518,187

References:
Company response to RUCO Data Request 1.14
Confirmed Company Calculations as Correct
Depreciation Rates Agrees with Respective Decisions

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Line No.	Acct. No.		Depreciation Rate Dec. 64282 01/01/02 To 7/31/10	Depreciation Rate Dec. 71845 08/01/10 To Present	2010 Additions	2010 Retirements	2010 Adjustments	2010 Depreciation Expense	2010 Balance	2011 Additions	2011 Retirements	2011 Adjustments	2011 Depreciation Expense	2011 Balance
1		Intangible Plant												
2	301	Organization	0.00%	0.00%				-	-				-	-
3	302	Franchises	See Acct. 11	See Acct. 111				-	935				-	935
4	303	Other Intangibles	See Acct. 11	See Acct. 111				159	2,438				159	2,438
5		Subtotal Intangible Plant			-	-	-	159	3,373	-	-	-	159	3,373
6		Source of Supply Plant												
7	310.1	Water Rights	0.00%	0.00%			(10)	-	156,158				-	156,158
8	310.3	Other Source of Supply Land	0.00%	0.00%				-	631,671				-	631,671
9	310.4	Wells - Other	See Acct. 11	See Acct. 111				-	-				-	-
10	314	Wells	2.59%	3.13%	15,311			182,367	6,486,066	2,934			203,060	6,489,000
11		Subtotal Source of Supply Plant			15,311	-	(10)	182,367	7,273,894	2,934	-	-	203,060	7,276,829
12		Pumping Plant												
13	320	Pumping Plant Land	0.00%	0.00%				-	5,544				-	5,544
14	321	Pumping Plant Structures & Improvements	2.59%	2.86%				2,928	108,350				3,099	108,350
15	325	Electtric Pumping Equipment	2.59%	5.88%	75,262	(75,524)		125,469	3,167,620	78,338	(31,050)		187,646	3,214,907
16	328	Gas Engine Equipment	2.59%	4.00%				7	223				9	223
17		Subtotal Pumping Plant			75,262	(75,524)	-	128,405	3,281,737	78,338	(31,050)	-	190,754	3,329,024
18		Water Treatment Plant												
19	330	Water Treatment Plant Land	0.00%	0.00%				-	-				-	-
20	331	Water Treatment Structures & Improvements	2.59%	2.50%	2,028			5,890	231,770	37,762			6,266	269,532
21	332	Water Treatment Equipment	2.59%	2.86%	714,129			60,963	2,612,862	1,030,800	(10,198)		89,322	3,633,464
22		Subtotal Water Treatment Plant			716,157	-	-	66,853	2,844,632	1,068,562	(10,198)	-	95,589	3,902,996
23		Transmission & Distribution Plant												
24	340	Transmission and Distribution Land	0.00%	0.00%				-	134,524				-	134,524
25	342	Storage Tanks	2.59%	2.00%	5,566			41,657	1,779,829	2,435			35,621	1,782,264
26	343	Transmission & Distribution Mains	2.59%	1.79%	243,092	(2,060)		524,548	23,364,896	128,029	(2,288)		419,357	23,490,638
27	344	Fire Sprinkler Taps	2.59%	2.00%	9,054			16,875	724,393	26,790			14,756	751,183
28	345	Services	2.59%	2.38%	80,594	(6,535)		121,510	4,892,589	129,470	(9,618)		117,870	5,012,441
29	346	Meters	2.59%	4.55%	7,503	(806)		27,902	822,381	1,052	(218)		37,437	823,215
30	348	Hydrants	2.59%	1.82%	256,406	(5,157)		40,217	1,897,969	225,382	(1,883)		36,577	2,121,467
31		Subtotal Transmission & Distribution Plant			602,215	(14,558)	-	772,709	33,616,581	513,158	(14,007)	-	661,618	34,115,732
32		General Plant												
33	389	General Plant Land	0.00%	0.00%				-	2,858				-	2,858
34	390	General Plant Structures	2.59%	2.50%				5,154	201,930				5,048	201,930
35	390.1	Leasehold Improvements	See Acct. 108	See Acct. 108.2				-	49,955	722			43	50,677
36	391	Office Furniture & Equipment	2.59%	6.67%	113			5,949	138,721	874			9,282	139,595
37	393	Warehouse Equipment	2.59%	5.00%				989	27,514	10,367			1,635	37,881
38	394	Tools, Shop & Garage Equipment	2.59%	4.00%	531			3,600	113,560	1,362			4,570	114,922
39	395	Laboratory Equipment	2.59%	5.00%	411			459	12,963	512			661	13,475
40	396	Power Operated Equipment	2.59%	6.67%	982			1,543	36,448	16,205	(50)		2,970	52,602
41	397	Communication Equipment	2.59%	6.67%	6,076			8,889	210,237	1,271	(2,400)		13,985	209,107
42	398	Miscellaneous Equipment	2.59%	3.33%				891	30,751	2,818			1,071	33,569
43		Subtotal General Plant			8,113	-	-	27,473	824,936	34,130	(2,450)	-	39,264	856,616
44		Plant in Service			$ 1,417,059	$ (90,082)	$ (10)	$ 1,177,966	$ 47,845,154	$ 1,697,121	$ (57,705)	$ -	$ 1,190,444	$ 49,484,570
45														
46		Accumulated Depreciation & Amort.						$ 12,005,832						$ 13,138,571
47		Net Plant in Service			$ 1,417,059	$ (90,082)	$ (10)		$ 47,845,154					$ 36,345,999

References:
Company response to RUCO Data Request 1.14
Confirmed Company Calculations as Correct
Depreciation Rates Agrees with Respective Decisions

Arizona Water Company
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PHOENIX OFFICE AND METER SHOP - ALLOCATION TO RATE BASE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED	(B) Navajo	(C) Verde Valley
1	3 Factor Allocation Factor		9.43%	12.52%
2	Phoenix Office Allocation			
3	Plant Classification			
4	Intangible Plant	$ 9,148	$ 863	$ 1,145
5	Source of Supply Plant	-	-	-
6	Pumping Plant	-	-	-
7	Water Treatment Plant	-	-	-
8	Transmission & Distribution Plant	-	-	-
9	General Plant	7,228,106	681,610	904,959
10	Total Gross Plant in Service (Sum L4 thru L9)	7,237,253	$ 682,473	$ 906,104
11	Less:			
12	Accumulated Depreciation	1,965,832	185,378	246,122
13	Net Utility Plant In Service (L10 less L12)	5,271,421	$ 497,095	$ 659,982
14	Less:			
15	Deferred Income Tax	29,186,404	$ 2,752,278	$ 3,654,138
16	Total Phoenix Office Allcoation (L13 less L15)	$ (23,914,983)	$ (2,255,183)	$ (2,994,156)
17				
18	Meter Shop Allocation			
19	Plant Classification			
20	Intangible Plant			
21	Source of Supply Plant	$ -	-	-
22	Pumping Plant	80	8	10
23	Water Treatment Plant	-	-	-
24	Transmission & Distribution Plant	2,050	193	257
25	General Plant	6,066	572	759
26	Total Gross Plant in Service (Sum L20 thru L25)	145,649	13,735	18,235
27	Less:	153,844	14,508	19,261
28	Accumulated Depreciation			
29	Net Utility Plant In Service (L26 less L28)	62,087	$ 5,855	$ 7,773
30	Less:	91,758	8,653	11,488
31	Deferred Income Tax		-	-
32	Total Phoenix Office Allcoation (L29 less L31)	$ 91,758	$ 8,653	$ 11,488
33				
34	Total Phoenix Office and Meter Shop Allocation			
35	Plant Classification			
36	Intangible Plant	$ 9,148	$ 863	$ 1,145
37	Source of Supply Plant	80	8	10
38	Pumping Plant	-	-	-
39	Water Treatment Plant	2,050	193	257
40	Transmission & Distribution Plant	6,066	572	759
41	General Plant	7,373,755	695,345	923,194
42	Total Gross Plant in Service	7,391,098	696,981	925,365
43	Less:			
44	Accumulated Depreciation	2,027,919	191,233	253,895
45		5,363,179	505,748	671,470
46	Less:			
47	Deferred Income Tax	29,186,404	2,752,278	3,654,138
48	Total Phoenix Office Allcoation (L9 - L10)	$ (23,823,225)	$ (2,246,530)	$ (2,982,668)

References:
See Company Schedule B-2 Appendix Page 5 of 5

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Schedule JLK-5
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ALLOWANCE FOR WORKING CAPITAL

LINE NO.	DESCRIPTION		(A) AMOUNT	(B) REFERENCE
1	Working Cash Requirement As Per Company	$	111,380	Company Schedule B-5, PG. 2 of 2
2	Working Cash Requirement As Per RUCO		(261,917)	RUCO Schedule JLK-6(1), L35
3	Adjustment	$	(373,297)	L2 - L1
4				
5	Material and Supplies Inventories As Per Company	$	62,073	Company Schedule B-5, PG. 2 of 2
6	Material and Supplies Inventories As Per RUCO		62,073	
7	Adjustment	$	-	L6 - L5
8				
9	Required Bank Balances As Per Company	$	132,163	Company Schedule B-5, PG. 2 of 2
10	Required Bank Balances As Per RUCO		132,163	
11	Adjustment	$	-	L10 - L9
12				
13	Prepayments & Special Deposits As Per Company	$	325,849	Company Schedule B-5, PG. 2 of 2
14	Prepayments & Special Deposits As Per RUCO		325,849	
15		$	-	L13 - L14
16				
17	TOTAL ADJUSTMENT (See RLM-2, Column (K))	$	(373,297)	Sum L3, L7, L11, L15

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RATE BASE ADJUSTMENT NO. 1 - PLANT ADJUSTMENTS
Summary of Post Test Year Plant Additions
Preliminary Costs vs Final Costs

Work Order Number	Account Description	Account Number	(A) Date const began.	(B) Date Construction is expected to be completed or was completed.	(C) Cost Per Company's Exhibit Sch B-2 Appendix Pages 1 thru 6	(D) Actual Cost 12/31/12 Per Company Response 1.3 (JMM 6-1)	(E) RUCO PLANT ADJUSTMENT VERDE VALLEY	(F) DEPRE RATE	(G) DEPRE ADJ
1-4814	Water Treatment Equipment	332	11/28/2011	6/25/2012	1,183,437	1,219,809	36,372	2.86%	520
1-4873	Water Treatment Equipment	332	10/3/2011	5/10/2012	445,986	424,376	(21,610)	2.86%	(309)
1-4874	Water Treatment Equipment	332	10/3/2011	4/2/2012	703,043	706,628	3,584	2.86%	51
1-4875	Water Treatment Equipment	332	10/3/2011	5/15/2012	588,322	571,255	(17,067)	2.86%	(244)
1-4928	Trans. & Dist. Mains	343	7/25/2012	12/31/2012	75,000	66,891	(75,000)	1.79%	(671)
1-4929	Services	345	4/9/2012	5/31/2012	205,800	195,537	(10,263)	2.38%	(122)
1-4930	Trans. & Dist. Mains	343,345	1/10/2012	5/23/2012	110,190	117,130	6,940	2.09%	72
1-4931	Trans. & Dist. Mains	343,345	2/3/2012	5/10/2012	64,971	67,251	2,280	2.09%	24
1-4932	Communication Equip	397	4/25/2012	12/31/2012	164,286	172,699	(164,286)	6.67%	(5,479)
	Plant Post Test Year Adjustments				$ 3,541,035	$ 3,541,575	$ (239,050)		$ (6,158)
	Phoenix Office Adjustments	391/394	1/15/2012	2/7/2012	$ 237,841	$ 236,555	$ (167)	GP	(86)
	TOTAL POST TEST YEAR ADJUSTMENTS						$ (239,216)		$ (6,244)

NOTES:

(1) Work Orders completed after June 30, 2012 adjusted downward in total.
(2) Work Orders completed prior to June 30, 2012 adjusted based on actual costs versus budgeted costs. Column (D) less Column (C)

ADJUSTMENTS AS FOLLOWS:

	(E)	(G)
Source of Supply	$ -	$ -
Pumping Plant	-	-
Water Treatment Equipment	1,279	18
Transmission & Distribution Plant	(76,043)	(697)
General Plant	(164,453)	(5,479)
	$ (239,216)	$ (6,158)

References:

Columns (A), (B) and (C'): Company Schedules B-2 Appendix pages 1 through 5
Column (D): Company Response to Data Request

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EXPLANATION OF RATE BASE ADJUSTMENT NO. 2 - WORKING CAPITAL

Line No.		(A) Company Test Year Adjusted Results	(B) RUCO Adj	(C) RUCO Adjusted Results	(D) Revenue Lag Days1	(E) Expense Lag Days2	(F) Net Lag Days [D - E]	(G) Lead / Lag Factor [F ÷ 365]	(H) Working Cash Requirement [A X G]
1									
2	Operating Expenses								
3	Purchased Power	$ 635,560		$ 635,560	28.818	30.87	(2.05)	(0.0056)	$ (3,573)
4	Payroll	1,306,798		1,306,798	28.818	14.00	14.82	0.0406	53,052
5	Purchased Water	-		-	28.818	-	28.82	0.0790	-
6	Chemicals	26,279		26,279	28.818	(18.11)	46.93	0.1286	3,379
7	Property & Liability Insurance	65,502		65,502	28.818	(45.27)	74.09	0.2030	13,296
8	Workman's Compensation Insurance	12,183		12,183	28.818	(46.50)	75.32	0.2064	2,514
9	Health Insurance	223,971		223,971	28.818	(8.92)	37.74	0.1034	23,157
10	Other O&M (Excluding Rate Case Expense)	1,219,792	(16,140)	1,203,652	28.818	(9.27)	38.09	0.1044	125,602
11	Federal Income Taxes	776,673	(189,217)	587,456	28.818	37.00	(8.18)	(0.0224)	(13,169)
12	State Income Taxes	171,094	(41,683)	129,411	28.818	37.00	(8.18)	(0.0224)	(2,901)
13	FICA Taxes	97,861		97,861	28.818	14.00	14.82	0.0406	3,973
14	FUTA & SUTA Taxes	3,253		3,253	28.818	83.10	(54.28)	(0.1487)	(484)
15	Property Taxes	235,027	(5,648)	229,379	28.818	212.00	(183.18)	(0.5019)	(115,118)
16	Registration, Svc. Contracts, & Misc. Fees	84,930		84,930	28.818	(98.83)	127.65	0.3497	29,702
17	Retirement Annuities (401k)	106,531		106,531	28.818	34.72	(5.90)	(0.0162)	(1,723)
18									
19									
20	Subtotal	4,965,453	(252,687)	4,712,766					117,707
21									
22	Interest Expense	732,342	120,487	852,829	29.53	91.25	(61.72)	(0.1691)	(144,210)
23									
24	Total								$ (261,917)

Columns (A), (D), and (E) Company Schs. B-5 Appendix page 1
Column (B) RUCO Schs. JLK-7, JLK-8

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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	$ 4,870,565	$ 63,203	$ 4,933,768	-	$ 4,933,768
2	Commercial	1,544,126	-	1,544,126		1,544,126
3	Industrial	3,699	-	3,699		3,699
4	Private Fire Service	45,049	-	45,049		45,049
5	Other Water Revenues	4,820	-	4,820		4,820
6	Total Water Revenues	$ 6,468,259	$ 63,203	$ 6,531,462	$ 1,330,169	$ 7,861,630
7						
8	Miscellaneous	$ 61,317	$ -	$ 61,317	-	$ 61,317
9	Total Operating Revenues	$ 6,529,576	$ 63,203	$ 6,592,779	$ 1,330,169	$ 7,922,948
10						
11	Operating Expenses					
12	Source of Supply Expenses:					
13	Purchased Water	$ -	$ -	$ -		$ -
14	Other	45,038	863	45,901		45,901
15	Pumping Expenses:					
16	Purchased Power	635,560	-	635,560		635,560
17	Purchased Gas	-	-	-		-
18	Other	232,130	18,553	250,683		250,683
19	Water Treatment Expenses	595,425	10,813	606,238		606,238
20	Transmission & Distribution Expenses	748,581	(41,351)	707,230		707,230
21	Customer Accounting Expenses	548,622	(205)	548,418		548,418
22	Sales Expense	1,177	-	1,177		1,177
23	Administrative & General Expenses	958,968	(16,538)	942,431		942,431
24	Total Operations & Maintenance Expense	$ 3,765,502	$ (27,865)	$ 3,737,637	$ -	$ 3,737,637
25						
26	Depreciation & Amortization Expenses	$ 1,166,958	$ (6,159)	$ 1,160,799		$ 1,160,799
27						
28	Taxes					
29	Federal Income Taxes	$ 134,814	$ 36,470	$ 171,284	416,172	$ 587,456
30	State Income Taxes	29,698	8,034	37,732	91,679	129,411
31	Property Taxes	212,747	2,178	214,925	14,454	229,379
32	Other	85,082	-	85,082		85,082
33	Total Taxes	$ 462,341	$ 46,682	$ 509,022	$ 522,305	$ 1,031,328
34						
35	Total Operating Expenses	$ 5,394,801	$ 12,658	$ 5,407,458	$ 522,305	$ 5,929,764
36	Operating Income	$ 1,134,775	$ 50,545	$ 1,185,321	$ 807,863	$ 1,993,184

References:
Column (A): JLK-8, Col. A
Column (B): JLK-8, Col. K
Column (C): Col. A + Col.B
Column (D): JLK-1, JLK-1(2), JLK-15
Column (E): Col.C + Col.D

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Schedule JLK-8

SCHEDULE OF OPERATING INCOME - TEST YEAR WITH RUCO ADJUSTMENTS

Line No.		[A] Test Year Ended 12/31/2011	(B) Adjustment Normalize Maintneance IS - 1	(C) Adjustment Rate Case Expense IS - 2	(D) Adjustment Fleet Fuel Expense IS - 3	(E) Adjustment Misc Expenses IS - 4	(F) Adjustment Depreciation Expense IS - 5	(G) Adjustment Declining Usage IS - 6	(H) Adjustment LEFT BLANK	(I) Adjustment Property Tax IS - 7	(J) Adjustment Income Tax IS - 8	(K) Total Pro Forma Adjustments	(L) Test Year Adjusted Results
									-				
1	Operating Revenues												
2	Residential	$ 4,870,565						$ 63,203				$ 63,203	$ 4,933,768
3	Commercial	1,544,126										-	1,544,126
4	Industrial	3,699										-	3,699
5	Private Fire Service	45,049										-	45,049
6	Other Water Revenues	4,820										-	4,820
7	Total Water Revenues (L2 thru L6)	$ 6,468,259	$ -	$ -	$ -	$ -	$ -	$ 63,203	$ -	$ -	$ -	$ 63,203	$ 6,531,462
8													
9	Miscellaneous	61,317										-	61,317
10	Total Operating Revenues (L7 + L9)	$ 6,529,576	$ -	$ -	$ -	$ -	$ -	$ 63,203	$ -	$ -	$ -	$ 63,203	$ 6,592,779
11													
12	Operating Expenses												
13	Source of Supply Expenses:												
14	Purchased Water	-										$ -	-
15	Other	45,038			(22)			885				863	45,901
16	Pumping Expenses:	-										-	-
17	Purchased Power	635,560										-	635,560
18	Purchased Gas	-										-	-
19	Other	232,130			(249)			18,802				18,553	250,683
20	Water Treatment Expenses	595,425			(67)			10,880				10,813	606,238
21	Transmission & Distribution Expenses	748,581	(40,585)		(766)							(41,351)	707,230
22	Customer Accounting Expenses	548,622			(205)							(205)	548,418
23	Sales Expense	1,177										-	1,177
24	Administrative & General Expenses	958,968		(11,725)	(70)	(4,743)						(16,538)	942,431
25	Total Operations & Maint. Exp (L14 thru L24)	$ 3,765,502	$ (40,585)	$ (11,725)	$ (1,378)	$ (4,743)	$ -	$ 30,566	$ -	$ -	$ -	$ (27,865)	$ 3,737,637
26													
27	Depreciation & Amortization Expenses	1,166,958	-	-	-	-	(6,159)	-	-	-	-	(6,159)	1,160,799
28													
29	Taxes												
30	Federal Income Taxes	134,814									36,470	36,470	171,284
31	State Income Taxes	29,698									8,034	8,034	37,732
32	Property Taxes	212,747								2,178		2,178	214,925
33	Other	85,082								-		-	85,082
34	Total Taxes (L30 thru L33)	$ 462,341	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,178	$ 44,504	$ 46,682	$ 509,022
35													
36	Total Operating Expenses (L25 + L27 + L34)	$ 5,394,801	$ (40,585)	$ (11,725)	$ (1,378)	$ (4,743)	$ (6,159)	$ 30,566	$ -	$ 2,178	$ 44,504	$ 12,658	$ 5,407,458
37	Operating Income (L10 less L36)	$ 1,134,775	$ 40,585	$ 11,725	$ 1,378	$ 4,743	$ 6,159	$ 32,637	$ -	$ (2,178)	$ (44,504)	$ 50,545	$ 1,185,321
												$ 50,545	

References:
Column A, JLK-9
Column B, JLK-10
Column C, JLK-11
Column D, JLK-12
Column E, JLK-13
Column F, JLK-14
Column J, JLK-16

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SCHEDULE OF OPERATING INCOME-TEST YR COMPANY ADJUSTMENTS

Line No.		[A] Test Year Ended 12/31/2011	(B) Adjustment Sales Tax IS - 1	[C] Adjustment Net Unbilled IS - 2	[D] Adjustment MAP IS - 3	(E) Adjustment ACRM IS - 4	(F) Adjustment Misc IS - 5	(G) Annualize YE Customers IS - 6	(H) Adjustment Weather IS - 7	(I) Adjustment Payroll IS - 8	(J) Adjustment Annualize Insurance IS - 9	(K) Adjustment Interest on Cust. Deposits IS - 10	(L) Adjustment Normalize Rents IS - 11	(M) Adjustment Adjust Purchase Water & Gas Exp IS - 12	(N) Adjustment Rate Case Expense IS - 13
1	Operating Revenues														
2	Residential	$ 5,541,864	$ (560,173)	$ 9,434	$ (13,201)	$ (36,213)	-	$ (7,943)	$ (63,203)						
3	Commercial	1,735,981	(197,052)	(3,976)	(290)	(16,529)	-	25,993							
4	Industrial	3,220	(281)	762	(1)	-	-								
5	Private Fire Service	50,861	(5,812)				-								
6	Other Water Revenues	5,347	(458)		(2)	(29)	(38)								
7	Total Water Revenues (L2 thru L6)	$ 7,337,272	$ (763,777)	$ 6,220	$ (13,494)	$ (52,771)	$ (38)	$ 18,050	$ (63,203)	$ -	$ -	$ -	$ -	$ -	$ -
8															
9	Miscellaneous	67,784	(6,466)		-	-									
10	Total Operating Revenues (L7 + L9)	$ 7,405,056	$ (770,243)	$ 6,220	$ (13,494)	$ (52,771)	$ (38)	$ 18,050	$ (63,203)	$ -	$ -	$ -	$ -	$ -	$ -
11															
12	Operating Expenses														
13	Source of Supply Expenses:														
14	Purchased Water	-													
15	Other	39,901						176	(885)	5,306					
16	Pumping Expenses:														
17	Purchased Power	635,560													
18	Purchased Gas	-													
19	Other	211,895						3,735	(18,802)	21,216				7,904	
20	Water Treatment Expenses	490,387			(13,176)			2,161	(10,880)	11,946					
21	Transmission & Distribution Expenses	605,975						(163)		57,523				3	
22	Customer Accounting Expenses	495,638						(133)		44,750			1,708	207	
23	Sales Expense	1,177													
24	Administrative & General Expenses	792,751						(213)		44,365	30,519	2,866	897		62,476
25	Total Operations & Maint. Exp (L14 thru L24)	$ 3,273,284	$ -	$ -	$ (13,176)	$ -	$ -	$ 5,563	$ (30,566)	$ 185,106	$ 30,519	$ 2,866	$ 2,605	$ 8,113	$ 62,476
26															
27	Depreciation & Amortization Expenses	1,045,969													
28															
29	Taxes														
30	Federal Income Taxes	510,075													
31	State Income Taxes	75,767													
32	Property Taxes	175,818													
33	Other	836,582	(770,243)							18,743					
34	Total Taxes (L30 thru L33)	$ 1,598,242	$ (770,243)	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,743	$ -	$ -	$ -	$ -	$ -
35															
36	Total Operating Expenses (L25 + L27 + L34)	$ 5,917,495	$ (770,243)	$ -	$ (13,176)	$ -	$ -	$ 5,563	$ (30,566)	$ 203,848	$ 30,519	$ 2,866	$ 2,605	$ 8,113	$ 62,476
37	Operating Income (L10 less L36)	$ 1,487,561	$ -	$ 6,220	$ (318)	$ (52,771)	$ (38)	$ 12,486	$ (32,636)	$ (203,848)	$ (30,519)	$ (2,866)	$ (2,605)	$ (8,113)	$ (62,476)

Columns (A) through columns (X) see Company Exhibit Schedule C-2

Columns (A) through columns (X) see (

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SCHEDULE OF OPERATING INCOME-TEST YR COMPANY ADJUSTMENTS

Line No.		(O) Adjustment Adjust A&G for BMP IS - 14	(P) Adjustment Fleet Fuel Expense IS -15	(Q) Adjustment Arsenic Treatmetn Exp IS - 16	(R) Adjustment Reflect New Vehicles IS - 17	(S) Adjustment Postage Expense (IS - 18	(T) Normalize T&D Maintenance IS - 19	(U) Adjustment Depreciation Expense IS - 20	(V) Adjustment Synchronise Interest Exp. IS - 21	(X) Adjustment Remove Other IS - 22	(Y) Adjustment Property Tax IS - 23	(Z) Adjustment Income Tax IS - 24	(AA) Total Pro Forma Adjustments	(BB) Test Year Adjusted Results
1	Operating Revenues													
2	Residential												(671,299)	$ 4,870,565
3	Commercial												(191,855)	1,544,126
4	Industrial												479	3,699
5	Private Fire Service												(5,812)	45,049
6	Other Water Revenues												(527)	4,820
7	Total Water Revenues (L2 thru L6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (869,013)	$ 6,468,259
8													-	
9	Miscellaneous												(6,466)	61,317
10	Total Operating Revenues (L7 + L9)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (875,480)	$ 6,529,576
11													-	
12	Operating Expenses												-	
13	Source of Supply Expenses:												-	
14	Purchased Water												-	-
15	Other		54		487								5,137	45,038
16	Pumping Expenses:												-	-
17	Purchased Power												-	635,560
18	Purchased Gas												-	-
19	Other		615		5,568								20,235	232,130
20	Water Treatment Expenses		166	113,315	1,506								105,038	595,425
21	Transmission & Distribution Expenses		1,893		17,146		66,204						142,606	748,581
22	Customer Accounting Expenses		506		4,585	1,362							52,984	548,622
23	Sales Expense												-	1,177
24	Administrative & General Expenses	23,575	172		1,560								166,218	958,968
25	Total Operations & Maint. Exp (L14 thru L24)	$ 23,575	$ 3,406	$ 113,315	$ 30,851	$ 1,362	$ 66,204	$ -	$ -	$ -	$ -	$ -	$ 492,218	$ 3,765,502
26													-	
27	Depreciation & Amortization Expenses							120,989					120,989	1,166,958
28													-	
29	Taxes												-	
30	Federal Income Taxes											(375,261)	(375,261)	134,814
31	State Income Taxes											(46,069)	(46,069)	29,698
32	Property Taxes										36,928		36,928	212,747
33	Other												(751,500)	85,082
34	Total Taxes (L30 thru L33)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,928	$ (421,330)	$ (1,135,902)	$ 462,341
35									-				-	
36	Total Operating Expenses (L25 + L27 + L34)	$ 23,575	$ 3,406	$ 113,315	$ 30,851	$ 1,362	$ 66,204	$ 120,989	$ -	$ -	$ 36,928	$ (421,330)	$ (522,694)	$ 5,394,801
37	Operating Income (L10 less L36)	$ (23,575)	$ (3,406)	$ (113,315)	$ (30,851)	$ (1,362)	$ (66,204)	$ (120,989)	$ -	$ -	$ (36,928)	$ 421,330	$ (352,786)	$ 1,134,775

Company Exhibit Schedule C-2

OPERATING INCOME ADJUSTMENT NO. 1
TRANSMISSION & DISTRIBUTION MAINTENANCE EXPENSE

	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
Transmission & Distribution Adjustment	$ 66,204	$ (40,585)	$ 25,619

Calculation of Average T&D Expense			
Years 2009, 2010, 2011			
	2009	2001	2011
T&D Expense for years shown	$ 330,457	$ 294,435	$ 274,018
Sum Total for three year period	$ 898,910		
Average T&D for three year period		$ 299,637	
Test Year Transmission & Distribution Expense		274,018	
RUCO T&D Proposed T&D Expense Normalized		$ 25,619	

References
Column (A) See Company Schedule C-2 page 28

OPERATING INCOME ADJUSTMENT NO. 2
RATE CASE EXPENSE ADJUSTMENT

Line No.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total for Northern Group	$ 441,576	$ (158,067)	$ 283,509
2				
3	Allocation Factor (L33)			53.70%
4				
5	Verde Valley (Sedona, Pinewood & Rimrock)			$ 152,254
6				
7	Amortization Period - 3 years			3
8				
9	RUCO Adjusted Rate Case Expense (L5 / L7)			$ 50,751
10				
11	Company Rate Case Expense as Filed (Company Sch. C-2 Appendix)			$ 62,476
12				
13	RUCO Pro Forma Rate Case Expense (L9 - L11)			$ (11,725)
14				
15	RUCO Adjustment			$ (11,725)
16				
17				
18	RUCO's Rate Base Expense Adjustment Calculation:			
19	Decision No. 64282, dated December 28, 2001, approved amount			
20	$216,982 for Arizona Water Company's Northern Group.		$ 216,982	
21				
22	Inflation Factor from January 1, 2002 through September 30, 2012			
23	Per Inflation Data.com		30.66%	
24				
25	Reasonable Amount of Rate Case Expense based on			
26	Decision No. 64282.		$ 283,509	
27				
28	RUCO Adjustment (Col. (A) Ln 1 - Col. (B) L 26)		$ 158,067	
29				
30				
31				
32	Allocation Factor Based on Number of Customers		Customers	Percent of Total
33	Verde Valley (Sedona, Pinewood, Rimrock)		10,564	53.70%

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OPERATING INCOME ADJUSTMENT NO. 3
Fleet Fuel Expense Adjustment

Line No.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO CALCUALTED COST	(C) RUCO ADJUSTMENT AS RECOMM'D
1	Number of fuel gallons used in test year (Total Company)	190,584	190,584	190,584
2				
3	Price per gallon of fuel (Obtained from U.S. Energy Info Admin)	$ 3.5530	$ 3.4680	$ 0.0850
4				
5	Adjusted due to reduced price per gallon of fuel (Total Co)	$ 677,144	$ 660,945	$ 16,200
6				
7				
8	Percentage allocated to Verde Valley based on			
9	three factor allocation formula.	$ 84,778	$ 82,750	$ 2,028
10				
11				
12			RUCO	
13	**Verde Valley**	COMPANY	CALCUALTED	RUCO ADJUSTMENT
14	**ALLOCATED TO OPERATING DEPARTMENTS:**	AS FILED	COST	BY DEPARTMENT
15	Source of Supply Expenses:	$ 54	$ 32	$ (22)
16	Pumping Expenses	615	366	(249)
17	Water Treatment Expenses	166	99	(67)
18	Transmission & Distribution Expenses	1,893	1,127	(766)
19	Customer Accounting Expenses	506	301	(205)
20	Administrative & General Expenses	172	102	(70)
21				
22	Totals By Department	$ 3,406	$ 2,028	$ (1,378)
23				
24				
25	**GASOLINE PRICES PROJECTED FOR YEAR 2013**			
26	First Quarter $ 3.39			
27	Second Quarter 3.58			
28	Third Quarter 3.59			
29	Fourth Quarter 3.31			
30	Total for Year $ 13.87	Average by Quarter	$ 3.4680	

References:

Column (A) Provided in AWC data response RUCO
Gasoline Prices by Quarter from Priceline Gas Price Forecasts

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OPERATING INCOME ADJUSTMENT NO. 4
MISCELLANEOUS EXPENSE

						Verde Valley 111			Navajo 081			Phoenix Office 300		
						Dues	Flowers	Other	Dues	Flowers	Other	Dues	Flowers	Other
1	081-93000-0000	4/27/2011	HEBER-OVERGAARD CHAMBER OF COMM	$ 70	MEMBERSHIP DUES				$ 70					
2	081-93000-0000	6/8/2011	PINETOP-LAKESIDE CHAMBER OF COMMERCE	305	MEMBERSHIP DUES				305					
3	081-93000-0000	3/17/2011	ARIZONA WATER FESTIVALS	300	SPONSORSHIPS						300			
4	081-93000-0000	5/19/2011	BRHS JUSTIN FLORES BENEFIT TOURNAMENT	500	SPONSORSHIPS						500			
5	081-92610-0000	9/16/2011	DOROTHYS FLOWERS & FINE ARTS	87	GIFTS & AWARDS					87				
6	081-92610-0000	3/30/2011	FLOWERS BY KARMA	89	GIFTS & AWARDS					89				
7	081-93000-0000	12/9/2011	FIESTA MEXICANA RESTAURANT	300	CHRISTMAS LUNCHEON						300			
8														
9	111-93000-0000	8/8/2011	SEDONA CANYON CHAMBER COMMERCE	450	MEMBERSHIP DUES	450								
10														
11	300-90100-0000	1/1/2011	ARIZONA CHAMBER OF COMMERCE	220	MEMBERSHIP DUES							220		
12	300-90100-0000	1/19/2011	ARIZONA INVESTMENT COUNCIL	329	MEMBERSHIP DUES							329		
13	300-92100-0000	5/25/2011	ARIZONA TOWN HALL	22	MEMBERSHIP DUES							22		
14	300-90100-0000	4/20/2011	WATER UTILITY ASSOC OF ARIZONA	1,317	MEMBERSHIP DUES							1,317		
15	300-92610-0000	1/31/2011	PHOENIX FLOWER SHOPS	25	GIFTS & AWARDS								25	
16	300-92610-0000	3/31/2011	PHOENIX FLOWER SHOPS	13	GIFTS & AWARDS								13	
17	300-92610-0000	7/21/2011	PHOENIX FLOWER SHOPS	35	GIFTS & AWARDS								35	
18	300-92610-0000	8/31/2011	PHOENIX FLOWER SHOPS	53	GIFTS & AWARDS								53	
19	300-93000-0000	2/28/2011	PHOENIX FLOWER SHOPS	22	GIFTS & AWARDS								22	
20	300-93000-0000	3/31/2011	PHOENIX FLOWER SHOPS	33	GIFTS & AWARDS								33	
21	300-92610-0000	12/31/2011	TERRYBERRY MANUFACTURING JEWELERS	21	GIFTS & AWARDS									21
22	300-92610-0000	12/31/2011	TERRYBERRY MANUFACTURING JEWELERS	838	GIFTS & AWARDS									838
23	300-90100-0000	6/14/2011	WATER UTILITY ASSOC OF ARIZONA	110	LUNCHEONS									110
24	300-90100-0000	11/9/2011	WATER UTILITY ASSOC OF ARIZONA	220	LUNCHEONS									220
25	300-92610-0000	4/30/2011	BW PLUS DOBSON RANCH INN	605	LUNCHEONS									605
26	300-92610-0000	3/17/2011	ALBERTSON'S LLC	107	EMPLOYEE PICNIC									107
27	300-92610-0000	8/31/2011	ARIZONA GOLF RESORT	445	AWARDS BANQUET									445
28	300-92610-0000	10/13/2011	CITRON SOUND SERVICES	67	AWARDS BANQUET									67
29	300-92610-0000	12/9/2011	CITRON SOUND SERVICES	132	AWARDS BANQUET									132
30	300-92610-0000	12/31/2011	CITRON SOUND SERVICES	22	AWARDS BANQUET									22
31	300-92610-0000	2/14/2011	PICNIC SPECIALTIES INC	494	EMPLOYEE PICNIC									494
32	300-92610-0000	2/14/2011	PICNIC SPECIALTIES INC	334	EMPLOYEE PICNIC									334
33	300-92610-0000	3/22/2011	POINTE HILTON SQUAW PEAK	3,406	AWARDS BANQUET									3,406
34														
35	Administration Expenses to be Adjusted			$ 10,971		$ 450	$ -	$ -	$ 375	$ 176	$ 1,100	$ 1,888	$ 181	$ 6,801
36	Membership Dues Adjusted at 50 Percent			$ 1,356		$ 225			$ 188			$ 944		
37	Administration Expenses After Adjustment			$ 9,615		$ 225	$ -	$ -	$ 188	$ 176	$ 1,100	$ 944	$ 181	$ 6,801
38	Phoenix Office Allocation		Navajo - 43%						$ 406	$ 78	$ 2,924	$ (406)	$ (78)	$ (2,924)
39			Verde Valley - 57%			$ 538	$ 103	$ 3,877				(538)	(103)	(3,877)
40														
41	Final Adjustment for Administration Expenses			$ 9,615		$ 763	$ 103	$ 3,877	$ 593	$ 254	$ 4,024	$ -	$ -	$ -
42														

43	Verde Valley	$ 4,743
44	Navajo	$ 4,872
		$ 9,615

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OPERATING INCOME ADJUSTMENT NO. 5
CALCULATION OF DEPRECIATION EXPENSE

Line No.	Acct. No.		Present Depreciation Rates	(A) Plant Balance Per GL	(B) Depre Exp Prior to Adjustments	(C) Depre Exp Post Test Year Plant Prior to Adjustments	(D) Depre Exp Phoenix Off Prior to Adjustments	(E) Depre Exp Meter Shop Prior to Adjustments	(F) Depre Exp As Filed By Company	(G) RUCO Depre Adjustments Post Test Yr Plant	(H) RUCO FINAL Depre Expense
1		Intangible Plant									
2	301	Organization	0.00%	-	-	-	-	-	-	-	-
3	302	Franchises	See Acct. 111	935	37	-	-	-	37	-	37
4	303	Other Intangibles	See Acct. 111	2,438	122	-	53	-	175	-	175
5		Subtotal Intangible Plant		3,373	159	-	53		212	-	212
6		Source of Supply Plant									
7	310.1	Water Rights	0.00%	156,158	-	-	-	-	-	-	-
8	310.3	Other Source of Supply Land	0.00%	631,671	-	-	-	-	-	-	-
9	310.4	Wells - Other	See Acct. 111	-	-	-	-	-	-	-	-
10	314	Wells	3.13%	6,488,999	203,106	-	-	-	203,106	-	203,106
11		Subtotal Source of Supply Plant		7,276,828	203,106	-	-	-	203,106	-	203,106
12		Pumping Plant				-	-				
13	320	Pumping Plant Land	0.00%	5,544	-	-	-	-	-	-	-
14	321	Pumping Plant Structures & Improvements	2.86%	108,350	3,099	-	-	-	3,099	-	3,099
15	325	Electtric Pumping Equipment	5.88%	3,214,908	189,037	-	-	-	189,037	-	189,037
16	328	Gas Engine Equipment	4.00%	223	9	-	-	-	9	-	9
17		Subtotal Pumping Plant		3,329,025	192,144	-	-	-	192,144	-	192,144
18		Water Treatment Plant				-	-				
19	330	Water Treatment Plant Land	0.00%	-	-	-	-	-	-	-	-
20	331	Water Treatment Structures & Improvements	2.50%	269,532	6,738	-	-	-	6,738	-	6,738
21	332	Water Treatment Equipment	2.86%	3,633,464	103,917	83,535	-	7	187,459	18	187,477
22		Subtotal Water Treatment Plant		3,902,996	110,655	83,535	-	7	194,197	18	194,216
23		Transmission & Distribution Plant									
24	340	Transmission and Distribution Land	0.00%	134,524	-	-	-	-	-	-	-
25	342	Storage Tanks	2.00%	1,782,264	35,645	-	-	-	35,645	-	35,645
26	343	Transmission & Distribution Mains	1.79%	23,490,637	420,482	3,455	-	14	423,951	(671)	423,280
27	344	Fire Sprinkler Taps	2.00%	751,183	15,024	-	-	-	15,024	-	15,024
28	345	Services	2.38%	5,012,440	119,296	6,258	-	-	125,554	(26)	125,528
29	346	Meters	4.55%	823,214	37,456	-	-	-	37,456	-	37,456
30	348	Hydrants	1.82%	2,121,468	38,611	-	-	-	38,611	-	38,611
31		Subtotal Transmission & Distribution Plant		34,115,731	666,514	9,713	-	-	676,241	(697)	675,544
32		General Plant									
33	389	General Plant Land	0.00%	2,858	-	-	-	-	-	-	-
34	390	General Plant Structures	2.50%	201,929	5,048	-	170	165	5,383	-	5,383
35	390.1	Leasehold Improvements	See Acct. 108.2	50,677	43	-	6,015	-	6,058	-	6,058
36	391	Office Furniture & Equipment	6.67%	139,595	9,311	-	43,098	93	52,502	-	52,502
37	393	Warehouse Equipment	5.00%	37,881	1,894	-	23	48	1,965	-	1,965
38	394	Tools, Shop & Garage Equipment	4.00%	114,922	4,597	-	1,233	348	6,178	-	6,178
39	395	Laboratory Equipment	5.00%	13,475	674	-	9	19	702	-	702
40	396	Power Operated Equipment	6.67%	52,603	3,509	-	-	12	3,521	-	3,521
41	397	Communication Equipment	6.67%	209,107	13,947	10,958	1,763	-	26,668	(5,479)	21,190
42	398	Miscellaneous Equipment	3.33%	33,569	1,118		30	-	1,148	-	1,148
43		Subtotal General Plant		856,615	40,141	10,958	52,341	685	104,125	(5,479)	98,646
44		Plant in Service		$ 49,484,568	$ 1,212,720	$ 104,206	$ 52,394	$ 692	$ 1,370,026	$ (6,158)	
45		Total Depreciation Test Year Adjusted: Col (F) Ln 44 + Col G Ln 44									$ 1,363,868
46		Less: Amortization of Contribution in Aid of Construction			2%	$ 10,153,446					$ (203,069)
47		Pro Forma Depreciation Expense: Col (H) Ln 45 + Ln 46									$ 1,160,799
48		Depreciation Expense as Filed by Company - Test Year Adjusted									$ 1,166,958
49		**RUCO Adjustment to Depreciation Expense and Accumulated Depreciation**									$ (6,159)

References

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OPERATING INCOME ADJUSTMENT NO. 6
DECLINING USAGE

DESCRIPTION	(A) COMPANY ESTIMATE	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
Residential Revenues - Reductions	$ (63,203)	$ 63,203	$ -
REVENUE REDUCTIONS	$ (63,203)	$ 63,203	$ -
Operating Expense Reductions			
Source of Supply - Other	$ (885)	$ 885	$ -
Pumping Expense - Other	(18,802)	18,802	-
Water Treatment Expense	(10,880)	10,880	-
OPERATING EXP. REDUCTIONS	$ (30,567)	$ 30,567	$ -

RUCO is taking the position that AWC's downward adjustment in revenues and expenses based on "calculated" reductions in usage is not a known and measurable change and is therefore not an appropriate adjustment in net operating expenses.

References:
Column (A) See Company Schedule C-2

OPERATING INCOME ADJUSTMENT NO. 7
PROPERTY TAXES

LINE NO.	Property Tax Calculation	(A) RUCO AS ADJUSTED	(B) RUCO RECOMMENDED
1	RUCO Adjusted Test Year Revenues - JLK-6	$ 6,592,779	$ 6,592,779
2	Multiplied by 2	2	2
3	Subtotal (Line 1 * Line 2)	$ 13,185,558	$ 13,185,558
4	RUCO Adjusted Test Year Revenues - 2011	6,592,779	
5	RUCO Recommended Revenue, Per Schedule JLK-1		7,922,948
6	Subtotal (Line 4 + Line 5)	$ 19,778,337	$ 21,108,505
7	Number of Years	3	3
8	Three Year Average (Line 5 / Line 6)	$ 6,592,779	$ 7,036,168
9	Department of Revenue Mutilplier	2	2
10	Revenue Base Value (L8 X L9)	$ 13,185,558	$ 14,072,337
11	Plus: 10% of CWIP -	-	-
12	Less: Net Book Value of Licensed Vehicles	-	-
13	Full Cash Value (L10 + L11 + L12))	$ 13,185,558	$ 14,072,337
14	Assessment Ratio	20.0%	20.0%
15	Assessment Value (L13 X L14)	$ 2,637,112	$ 2,814,467
16	Composite Property Tax Rate (L19 / L15)	8.1500%	8.1500%
17			
18	RUCO Proposed Property Tax Expense (L15 X L16))	$ 214,925	
19	Company Proposed Property Tax	212,747	
20			
21	RUCO Test Year Adjustment (L16 - L17)	$ 2,178	
22	Property Tax - RUCO Recommended Revenue (L15 X L16)		$ 229,379
23	RUCO Test Year Adjusted Property Tax Expense (L18)		214,925
24	Increase/(Decrease) to Property Tax Expense		$ 14,454
25			
26	Increase/(Decrease) to Property Tax Expense		$ 14,454
27	Increase in Revenue Requirement (L5 - L4)		1,330,169
28	Increase /(Decrease) to Property Tax per Dollar Increase in Revenue (L26 / L27)		**1.0867%**

OPERATING INCOME ADJUSTMENT NO. 8
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(B) AMOUNT
1	Federal Income Taxes as Filed - See Company Schedule C-2 Page 9	$ 134,814
3	RUCO Calculated Income Tax - See JLK - Schedule 1 Page 2 Ln 52	171,284
5	RUCO Calculated Adjustment	$ 36,470

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COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO RECOMMENDED	(D) CAPITAL RATIO	(E) COST RATE	(F) WEIGHTED COST RATE
1	Long-Term Debt	$ 75,000,000	$ -	$ 75,000,000	48.95%	6.82%	3.34%
2							
3	Common Equity	78,221,194	-	78,221,194	51.05%	8.75%	4.47%
4							
5	Total Capitalization	$ 153,221,194	$ -	$ 153,221,194	100.00%		
6							
7							
8	WEIGHTED AVERAGE COST OF CAPITAL						7.81%

References:
Columns (A) Thru (F): WAR Testimony

ARIZONA WATER COMPANY

DOCKET NO. W-01445A-12-0348

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MARCH 1, 2013

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Attachment A – NASUCA Resolution Discouraging State Regulatory Commissions from Adopting Automatic Adjustment Charges for Water Company Infrastructure Costs
Attachment B – Testimony of Sonny Popowski, Consumer Advocate for the State of Pennsylvania
Attachment C – Increasing Use of Surcharges on Consumer Utility Bills, Prepared by Larkin & Associates, PLLC for AARP

EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's ("RUCO") analysis of Arizona Water Company's application for a permanent rate increase for its Northern Group, filed with the Arizona Corporation Commission on August 1, 2012, RUCO is making the following recommendations:

RUCO recommends that the Arizona Corporation Commission reject Arizona Water Company's request for a Distribution System Improvement Charge, and its rate design method that addresses declining usage.

RUCO recommends approval of Arizona Water Company's request for the continuation of an Arsenic Cost Recovery Mechanism to include all of the Verde Valley systems and the establishment of an ACRM for the Navajo system.

RUCO neither agrees with nor disagrees with Arizona Water Company's off-site facilities fee tariff, but reiterates the reasons it has given in other rate case proceedings as to why it believes that delaying the recognition of contributions-in-aid-of construction as a deduction to rate base is not in the best interest of ratepayers.

INTRODUCTION

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

A. My Name is William A. Rigsby. I am the Chief of Accounting and Rates for 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 utility regulation and your educational background.

A. I have been involved with utility 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. Appendix 1, which is attached to my direct testimony on the cost of capital issues in this case, 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 RUCO's positions on a number of requests contained in Arizona Water Company's ("AWC" or "Company") application for a permanent increase in rates ("Application") for the

Company's Northern Group operating systems. AWC filed its Application with the Arizona Corporation Commission ("ACC" or "Commission") on August 1, 2012 using a test year ending on December 31, 2011 ("Test Year").

Q. Will RUCO be filing testimony on the required revenue, rate design and cost of capital issues associated with AWC's Application?

A. Yes. RUCO witness Jorn L. Keller will provide direct testimony presenting RUCO's recommendations on required revenue. RUCO witness Robert B. Mease will sponsor RUCO's direct testimony on rate design. As I noted above, I have also filed, under separate cover, direct testimony on the cost of capital issues in this case.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the specific issues that you will address in your direct testimony.

A. My direct testimony will address AWC's requests for a Distribution System Improvement Charge ("DSIC"), the continuation and establishment of Arsenic Cost Recovery Mechanisms and the Company's request for an Off-Site Facilities Fee tariff that delays recognition of contributions-in-aid-of-construction ("CIAC") as a deduction from rate base until plant funded by the hook-up fees is placed into service.

Q. Please provide a brief summary of RUCO's recommendations.

A. RUCO is making the following recommendations:

Distribution System Improvement Charge

RUCO recommends that the Commission reject Arizona Water Company's request for a DSIC, and the Company's rate design method that addresses declining usage.

Arsenic Cost Recovery Mechanism

RUCO recommends approval of Arizona Water Company's request for the continuation of an Arsenic Cost Recovery Mechanism to include all of the Verde Valley systems and the establishment of an ACRM for the Navajo system.

Off-Site Facilities Fee Tariff

RUCO neither agrees with nor disagrees with AWC's Off-Site Facilities Fee tariff, but reiterates the reasons it has given in other rate case proceedings as to why it believes that delaying the recognition of CIAC as a deduction to rate base is not in the best interest of ratepayers.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

Q. Have you reviewed the direct testimony of Joseph D. Harris that addresses AWC's request for a DSIC surcharge?

A. Yes.

Q. Briefly explain AWC's DSIC surcharge request.

A. According to Mr. Harris' testimony, AWC is seeking Commission approval of a surcharge mechanism that would recover the fixed costs associated with DSIC-eligible utility plant additions net of retirements placed into service between general rate cases. Under AWC's proposal the DSIC would be phased-in each year and capped at 7.50 percent of the annual amount billed to customers. As new rates go into effect at the conclusion of future general rate case proceedings, the DSIC will be reset to zero as DSIC-eligible plant is rolled into rate base and the costs are included in the new base rates established by the Commission. Under the Company's proposal, new DSIC-eligible utility plant additions not included in the general rate case would be included in new annual DSIC filings. Mr. Harris states in his testimony that no DSIC filing will be made if, in any annual period between, the affected system is earning a rate of return that exceeds the authorized rate of return for that system.

...

Q. What is RUCO's recommendation regarding the Company-proposed DSIC?

A. RUCO recommends that the Commission reject the Company-proposed DSIC in favor of the traditional ratemaking process. To support its recommendation, RUCO lists four reasons.[1] First, AWC is seeking recovery of routine plant improvements outside of a rate case that would normally be recovered in a general rate case proceeding. Second, the DSIC is a one-sided mechanism which works only in the interest of the shareholder. While it allows accelerated cost recovery for new plant, it fails to consider reduced operations and maintenance expense ("O&M") savings attributable to the new plant. Third, there is no federal or state requirement mandating the types of routine plant additions that AWC seeks recovery for through the Company-proposed DSIC. Fourth, AWC has not proven that it would not be able to ensure safe and reliable water service or achieve cost recovery absent the DSIC. Therefore, there is no need for the Commission to adopt a special surcharge for such routine additions.

...

[1] There are also legal concerns with the implementation of the DSIC which, if necessary, RUCO will address in its legal briefs.

Q. In regard to RUCO's first reason for rejecting the Company-proposed DSIC, are the types of infrastructure improvements that would be recovered through the DSIC extraordinary in nature?

A. No. The types of infrastructure improvements for which the Company seeks cost recovery for through a DSIC mechanism are routine in nature. These are plant improvements that any regulated utility would normally make as existing assets reach the end of their useful lives. There is nothing extraordinary about these types of plant additions. The normal regulatory procedures allow cost recovery for these types of plant additions after a determination of prudency and that the additions meet the used and useful standard during a general rate case proceeding when all of the various ratemaking elements are taken into consideration. RUCO has consistently opposed the use of cost recovery mechanisms that do not allow for the type of thorough analysis that takes place in a general rate case proceeding.

Q. Why is it important to consider all of the ratemaking elements when setting new rates?

A. Because the addition of new plant that replaces aging plant can have an impact on operating expenses which are recovered by a utility on a dollar-for-dollar basis in new rates. For example, new additions may be responsible for lower purchased pumping power costs as a result of improved system efficiency and lower employee wage expense as a result of less time spent on repairing aging plant items after normal hours. Under the Company-proposed DSIC, AWC would enjoy the benefit of receiving a return on and a return of its investment in new plant through a surcharge established between general rate case proceedings. Unfortunately, ratepayers receive no benefit from any cost savings that are related to the plant additions that they will be paying for through the DSIC. Any cost savings resulting from new plant additions recovered through the Company-proposed DSIC would be pocketed by AWC between general rate case proceedings.

Q. In regard to RUCO's third reason for rejecting the Company-proposed DSIC, are there any federal or state regulations that require the Commission to approve a mechanism that is similar to the ACRM?

A. No. Unlike the circumstances surrounding plant that was required for reducing the level of arsenic in drinking water, there are no federal or state requirements that warrant the implementation of a mechanism similar to the Arsenic Cost Recovery Mechanism ("ACRM")[2] for the recovery of aging plant between general rate cases. RUCO believes that adjustor mechanisms are extraordinary rate recovery devices that are permitted for certain narrow circumstances. In RUCO's view, the routine replacement

[2] The ACRM was adopted by the Commission in order to allow Arizona water providers to recover the costs associated with meeting more stringent arsenic level standards imposed by the federal government.

of aging infrastructure, that would be recovered through the Company-proposed DSIC, does not qualify as an extraordinary circumstance that requires a mechanism such as the ACRM which was specifically designed to address a one-time event that impacted dozens of Arizona water companies simultaneously. In this case, AWC cites excessive water loss, which is something that the Company should keep in check as a matter of routine cost management. The Company's failure to perform ordinary maintenance is not a reason for the institution of a DSIC.

Q. Please discuss RUCO's fourth reason for rejecting the DSIC.

A. RUCO believes that AWC should replace aging infrastructure as part of the Company's normal course of infrastructure improvements to ensure continued safety and reliability. RUCO, however, does not find that a DSIC surcharge is necessary for AWC to meet the Company's obligation to provide safe and reliable water service. AWC does not contend that the denial of a DSIC would change its ability to meet the Company's statutory and regulatory commitments and AWC does not allege that it is financially unable to make necessary and prudent infrastructure replacements without the DSIC.

...

Q. Does the National Association of State Consumer Advocates ("NASUCA") endorse mechanisms similar to the DSIC?

A. No. NASUCA issued a resolution in 1999 (Attachment A) that opposes the adoption and implementation of mechanisms such as the Company-proposed DSIC. The resolution lists a number of sound reasons why such mechanisms should be rejected by state utility commissions.

Q. Can you cite any research that illuminates the deficiencies in the Company-proposed DSIC surcharge?

A. Yes. Ken Costello, a Principal with the National Regulatory Research Institute ("NRRI"), published a survey report on cost trackers (similar to the Company-proposed DSIC) in September 2009. In his report, Mr. Costello noted the following:

> "Cost trackers can, in various ways, result in higher utility costs. First, they undercut the positive effects of regulatory lag on a utility's costs. "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates. Economic theory predicts that the longer the regulatory lag, the more a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility, consequently, would have an incentive to minimize additional costs. Commissions rely on regulatory lag as an important tool for motivating utilities to act efficiently. As economist and regulator Alfred Kahn once remarked:
>
>> "Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards to their opposites; companies can for a time keep the higher profits they reap from a superior

> performance and have to suffer the losses for a poor one."
>
> Rational utility management, as a general rule, would exert minimal effort in controlling costs if it has no effect on the utility's profits. This condition occurs when a utility is able to pass through (with little or no regulatory scrutiny) higher costs to customers with minimal consequences for sales. Cost containment constitutes a real cost to management. Without any expected benefits, management would exert minimum effort on cost containment. The difficult problem for the regulator is to detect when management is lax. Regulators should concern themselves with this problem; lax management translates into a higher cost of service and, if undetected, higher rates to the utilities customers. Regulators should closely monitor and scrutinize costs, such as those subject to cost trackers, that utilities have little incentive to control."[3]

Q. Can you cite other cases or testimony that supports RUCO's position on this issue?

A. Yes. In April of 2009, Sonny Popowsky, the Consumer Advocate for the Commonwealth of Pennsylvania, offered testimony before the Pennsylvania House Consumer Affairs Committee regarding a House Bill that would have approved a mechanism similar to the Company-proposed DSIC for natural gas utilities (Attachment B). In his testimony, to support his argument against the adoption of the natural gas mechanism, Mr. Popowski quoted Commonwealth Court Judge Leavitt in her opinion on a Collection System Improvement Charge, being sought by Pennsylvania-American Water Company:

---

[3] Costello, Ken, "How Should Regulators View Cost Trackers?" Washington, DC: National Regulatory Research Institute, Pages 4-5 [footnotes excluded]

> "The surcharge is quite different from a base rate. In Pennsylvania, as in most jurisdictions, rates for public utilities are set using what is known as the test year concept, which requires taking a snapshot of the utility's revenues, expenses and capital costs during a one-year period. The object of using a test year is to reflect typical conditions. Test year expenses may be adjusted or normalized where atypical or non-recurring. Under the test year concept, revenues, expenses and capital costs are to be simultaneously reviewed for the same period of time so that a utility may prove its new rates are "just and reasonable."

Mr. Popowski went on to state the following:

> "Unlike a traditional base rate case, in which all costs and all revenues are considered simultaneously, a DSIC is a one-way street that can only increase rates between rate cases, even if a utility's other costs are going down or its revenues are going up. In setting utility rates, it is important to look at all the utility's costs and revenues, not just a single utility cost item that may be added between rate cases."

Q. Can RUCO cite any other studies that dispute the benefits of adjustor mechanisms such as the DSIC mechanism discussed in your testimony?

A. Yes. In May of 2012, Ralph Smith of Larkin & Associates, PLLC, who has testified in a number of rate case proceedings on behalf of ACC Staff and RUCO, recently authored a report on the increasing use of surcharges on consumer utility bills for the American 1 Association of Retired Persons ("AARP") which I've attached to my direct testimony (Attachment C). In his report, Mr. Smith explains how, for many consumers, home utility bills are becoming more and more cluttered with new fees and surcharges to pay for everything from investment in new gas pipelines to environmental compliance costs. Mr. Smith points out that that these types of surcharges are departures from the traditional utility rate setting process. He also warns that surcharges, such as a SWIP or DSIC, can result not only in increased costs to consumers, but additional undesirable consequences such as reducing utility incentives to control costs and shifting utility business risks away from investors and onto customers.

Q. Has the Commission rejected such mechanisms in prior cases?

A. Yes, in a prior Arizona-American Water Company rate case proceeding, the Commission adopted the recommendations of ACC Staff and RUCO and rejected a similar cost recovery mechanism identified as an Infrastructure Improvement Surcharge ("IIS"). Decision No. 72047 stated the following:

> "The Company admits the surcharge would cover routine investments in such items as meters, mains, hydrants, tanks and booster stations, and while the Company proposed a cap on the increase between rates, the Company has not quantified the amount of the proposed surcharge. We agree with RUCO and Staff that the recovery of expenditures for plant additions and improvements does not warrant the extraordinary ratemaking device of an adjuster mechanism, and will therefore not grant the request for institution of an IIS."

Q. Do the customer bill impacts estimated by AWC justify the adoption of the DSIC?

A. No. While an argument could be made that the Company-proposed DSIC would result in gradual rate increases that would be more palatable to both ACC Commissioners and to ratepayers, if the Commission were to adopt the Company-proposed DSIC, ratepayers could be looking at a rate increase in every year between general rate cases. Municipal systems don't even impose such frequent rate hikes on their water and wastewater customers. This steady stream of rate increases is certainly a departure from the Commission's prior preference for rate stability between general rate cases. While it is possible that the adoption of the Company-proposed DSIC may mitigate rate shock in future general rate cases, the Commission would have to weigh this with the fact that this steady stream of rate increases will benefit the Company more than AWC ratepayers given the fact that the surcharge amounts will not reflect any dollar-for-dollar cost reductions in operating expenses that are associated with the new plant.

Because ACC Staff, and intervenors, such as RUCO, will not have the opportunity to look closely at the plant additions being placed into service between rate cases, the possibility exists that imprudent expenditures would not be discovered until a general rate case proceeding. By then ratepayers could have been overcharged for imprudent plant expenditures for a number of years. Furthermore, ratepayers who leave the affected systems will not even see any savings from new rates, established in a general rate case proceeding, that reflect lower operating costs or the disallowance of imprudent plant expenditures. For the reasons that I've given above, I believe that the Commission should reject the Company-proposed DSIC.

Q. Is there any way to mitigate the problems with the DSIC that you discussed above?

A. Possibly. In July 2011, David D. Dismukes, Ph.D. (who recently testified for ACC Staff in the recent Southwest Gas Corporation rate case proceeding), filed testimony[4] on a surcharge mechanism similar to the Company-proposed DSIC in a proceeding before the Maryland Public Service Commission. As an alternative to an accelerated natural gas pipe replacement plan that was being proposed in that proceeding by WGL Holdings, Inc., Mr. Dismukes recommended an Operations & Maintenance ("O&M") expense offset that would apply a specified dollar credit to every mile of replaced pipe. A similar credit could be applied to every foot of replacement line that AWC would recover through the Company-proposed DSIC. Mr. Dismukes recommendation makes good sense from the standpoint that O&M expense would drop as aging infrastructure is replaced. In this case, an O&M credit would have the effect of lowering the increased pro-forma level of O&M expense that it is being proposed by AWC in this case which would be embedded in base rates. The adoption of an O&M credit, that would be applied to customer bills at the same time

[4] Dismukes, David E., Ph.D., Direct Testimony on Behalf of the Maryland Office of People's Counsel, Case no. 9267, filed July 27, 2011

that potential DSIC surcharges go into effect, would produce fairer rates in RUCO's view.

Q. Did the Maryland Public Service Commission approve the surcharge portion of the plan being proposed by WGL Holdings, Inc.?

A. No. In its final decision[5] on the matter, the Maryland Public Service Commission stated that "although the Commission does agree with WGL [Holdings, Inc.] that "safe and reliable infrastructure is its highest priority," it maintains that 'infrastructure investments do not justify a surcharge' to be imposed on customers. The Maryland Commission authorized WGL Holdings, Inc. to implement the initial phase of its proposed accelerated natural gas pipe replacement plan but stated that it would address cost recovery in appropriate future rate cases.

Q. Has RUCO made any downward adjustment to the Company-proposed increase in O&M expense?

A. Despite concerns that RUCO has with AWC's proposed increase in O&M expense, RUCO has not made any adjustment. But if the Commission were to adopt the Company-proposed DSIC with no type of O&M credit, RUCO believes that a downward adjustment should be made.

---

[5] Maryland Public Service Commission Order No. 84475 issued on November 14, 2011

AWC EASTERN GROUP DECISION

Q. Did the Commission adopt the DSIC surcharge mechanism that AWC proposed in the Eastern Group rate case proceeding?

A. No. However, during the Regular Open Meeting conducted on February 12, 2013, the Commission ordered the AWC Eastern Group docket[6] to remain open in order to allow the parties to the case, and any other party that wishes to intervene, to enter into settlement discussions on a proposed DSIC mechanism. A final decision on a settlement agreement that is reached by the parties will be voted on by the five Commissioners no later than the Regular Open Meeting scheduled for Tuesday and Wednesday, June 11, and 12, 2013.

Q. Will RUCO participate in the settlement discussions?

A. Yes. However, RUCO cannot say at this time whether or not it will support the DSIC mechanism, if any, that results from the settlement discussions that the Commission has ordered.

ARSENIC COST RECOVERY MECHANISM

Q. Is AWC requesting an ACRM for the Company's Northern Group systems?

A. Yes. AWC is requesting that the Commission approve continuation and expansion of the ACRM for its Verde Valley system, as opposed to the

[6] Docket No. W-01445A-11-0310.

ACRM that is currently in effect for the Sedona system only, and seeking authorization of an ACRM for its Navajo system

Q. Does RUCO oppose AWC's request for a continuance of an ACRM for the Company's Northern Group systems?

A. No. RUCO recommends that the Commission adopt AWC's request for a continuance and expansion of the Verde Valley water system and the establishment of an ACRM for the Navajo water system.

OFF SITE FACILITIES FEE TARIFF

Q. What is RUCO position on AWC's request for an Off-Site Facilities Fee tariff that delays recognition of contributions-in-aid-of-construction ("CIAC") until plant funded by hook-up fees is placed into service?

A. RUCO neither agrees with nor disagrees with AWC's off-site facilities fee tariff that delays the recognition of CIAC as a deduction to rate base until the plant funded by hook-up fees is placed into service. However, RUCO continues to stand by its position, which RUCO has taken in other rate case proceedings, that delaying the recognition of CIAC as a deduction to rate base is not in the best interest of ratepayers for a number of reasons.

...

OTHER ISSUES

Q. Are there other issues in AWC's Application that need to be addressed?

A. Yes. AWC is requesting full consolidation of the Company's Sedona operating system with the Verde Valley system. AWC also wants to be able recover a higher percentage of the Northern Group's overall revenue requirement through the fixed basic service charge.

Q. Will you be addressing these issues in your direct testimony?

A. No. These issues will be discussed in RUCO's rate design testimony that will be filed on March 5, 2013.

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

A. No, it does not.

Q. Does this conclude your direct testimony on AWC's Northern Group rate case filing?

A. Yes, it does.

ATTACHMENT A

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

ATTACHMENT B

BEFORE THE PENNSYLVANIA HOUSE CONSUMER AFFAIRS COMMITTEE

Testimony of

SONNY POPOWSKY
CONSUMER ADVOCATE

Regarding

House Bill 744
Natural Gas Distribution System Improvement Charge

Harrisburg, PA
April 23, 2009

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Chairman Preston, Chairman Godshall
and Members of the House Consumer Affairs Committee

My name is Sonny Popowsky. I have served as the Consumer Advocate of Pennsylvania since 1990, and I have worked at the Office of Consumer Advocate since 1979. Thank you for this opportunity to present testimony to this Committee regarding House Bill 744, which would allow natural gas utilities in Pennsylvania to increase their rates automatically to reflect the capital costs of distribution plant that is added to service between base rate cases. As currently drafted, House Bill 744 would allow automatic increases in rates to reflect the value of new plant additions, but would not reflect reductions in the value of existing distribution plant resulting from depreciation and retirements during the same period. As such, the proposed distribution system improvement charge (DSIC) contained in HB 744 is one-sided and unfair to consumers. In addition, HB 744 contains no limit on the overall level of rate increases that can be obtained by natural gas utilities through these automatic adjustment clauses, which means that rates can be increased indefinitely without a Commission review of the utility's overall base rates. If the General Assembly chooses to proceed with HB 744, then I would respectfully submit that the legislation must be amended in order to correct these flaws.

As you know, the model used to support the proposed natural gas distribution system improvement charge is found in a Public Utility Code provision that was added for water companies in 1996 to allow water utilities to increase rates between base rate cases in order to cover the costs of new distribution improvements. At that time, many water utilities were filing base rate cases almost annually to cover the cost of new infrastructure required to meet state and federal safe drinking water laws.

In contrast, until 2008, several of our major natural gas utilities had not filed base rate cases in decades. Prior to 2008, the last base rate increase for PECO Gas was in 1988, twenty years earlier. The last base rate case filed by Columbia before 2008 was in 1995 and the last Equitable case prior to 2008 was in 1997. To this day, UGI and Dominion (Peoples) have not filed a base rate case since 1995. I am not aware of any evidence that these utilities have been unable to maintain safe natural gas service and make necessary infrastructure improvements during those many years in which their base rates remained unchanged. When Pennsylvania natural gas utilities have been able to provide service to customers without increasing their base rates for 10, 15 or 20 years, why would we pass a law that allows them to raise those rates automatically every three months?

This is not a hypothetical question. In November 2007, PECO Gas issued a press release announcing that it had just completed $12.3 million in upgrades to its suburban Philadelphia natural gas facilities, including the replacement of 58,000 feet of cast iron and bare steel mains. And, PECO Gas did all this without raising its base rates and without a DSIC. In the press release announcing the system improvements that PECO issued on November 6, 2007, the Company stated:

> During the past 20 years, PECO has made significant upgrades to its natural gas delivery system and expanded capacity, serving about 7,000 new customers each year – all without an increase in the company's delivery and service charges since 1988. By saving customers money through the use of new technologies, increasing sales, operational mergers and other efficiencies PECO charges remain among the lowest in Pennsylvania.

That is how ratemaking is supposed to work. Between base rate cases, a utility makes needed investments that increase costs, but the utility may also add customers who provide more revenues, or it may operate more efficiently to reduce costs in other areas. Most importantly, the level of investment in its existing infrastructure goes down in value due to depreciation and retirements. In a base rate case, both the increases and decreases are taken into account.

In a base rate case, all of the utility's costs and revenues are looked at together in order to determine whether the company needs to increase its base rates. In contrast, a distribution system improvement charge simply takes out of context one cost element – the cost of new pipes – and raises the utility's overall rates to reflect that additional cost, without considering any offsetting changes.

It is true that improvements to our natural gas infrastructure cost money, and utilities that make prudent investments that are used to serve the public are permitted an opportunity to recover a return of and earn a fair return on those investments. That does not mean, however, that we need to remove the protections of the Public Utility Code in order to make it easier for utilities to increase their rates between rate cases, without hearings and without any meaningful ability for customers to oppose such increases.

Traditionally, utilities in Pennsylvania and across the Nation have recovered the cost of infrastructure improvements through base rate cases, in which all of the utilities' investments, expenses, and revenues are examined at the same point in time. As I mentioned earlier, in 1996, the General Assembly created an exception to this process for water utilities at a time when water companies contended that they were subject to very substantial new infrastructure requirements. The investments recovered through these surcharges, which are permitted to increase every three months, are subject to Commission audit to ensure that they are correctly calculated and accounted for, but they are not reviewed by the Commission to determine whether the investments are needed or are prudently incurred before their costs are placed in rates. That is why these provisions are called "automatic adjustment" clauses in both the existing Section 1307 of the Public Utility Code and in the proposed House Bill 744. Initially, the DSIC surcharges for water utilities were limited by the PUC to no more than 5% of the utility's revenues, but in 2007, the Commission approved – over the objection of my Office, the Office of Small Business Advocate, the Office of Trial Staff, and the Company's large industrial customers -- an increase in the DSIC surcharge of Pennsylvania American Water Company (PAWC) from 5% to 7.5%. Indeed, it appears from the Commission's Order in that case, that the Commission believes it has the discretion to allow the surcharge to increase to 10% or even higher if it chooses to do so.

As you may be aware, PAWC also sought to implement a surcharge for its wastewater (sewer) division called a Collection System Improvement Charge (or CSIC). The PUC approved that surcharge and my Office successfully appealed on the ground that the automatic capital recovery surcharges permitted under the Public Utility Code are limited to water utilities. The Commonwealth Court agreed with my Office that the CSIC was not permitted under the Public Utility Code, but the Court also discussed the policy objections to a clause that allows a utility to recover capital expenditures through an automatic surcharge mechanism. As stated by Judge Leavitt in her Opinion for the Commonwealth Court:

> Utility's Wastewater Charge will entail regulatory oversight that amounts to no more than a mathematical exercise. The after-the-fact audit will require Utility to show only that it did, in actuality, spend the funds for the intended purpose and not, for example, that a new pumping station was needed and was operating effectively.....
>
> .... the "cursory" review undertaken for a surcharge is not a substitute for the review undertaken in a base rate case to determine whether a rate is just and reasonable.

Popowsky v. PA PUC, 869 A.2d 1144, 1156 (Comm. Ct. 2005).

More important than the lack of prior substantive Commission review, in my opinion, is the fact that a surcharge for capital expenditures is contrary to the general concept of just and reasonable rates because it allows recovery of a single cost increase, while ignoring all of the other changes, both positive and negative, that occur between base rate cases. Again, to quote from Judge Leavitt's opinion for the Commonwealth Court in the PAWC CSIC case:

> The surcharge is quite different from a base rate. In Pennsylvania, as in most jurisdictions, rates for public utilities are set using what is known as the test year concept, which requires taking a snapshot of the utility's revenues, expenses and capital costs during a one-year period. The object of using a test year is to reflect typical conditions. Test year expenses may be adjusted or normalized where atypical or non-recurring. Under the test year concept, revenues, expenses and capital costs are to be simultaneously reviewed for the same period of time so that a utility may prove its new rates are "just and reasonable."

869 A.2d at 1152.

Unlike a traditional base rate case, in which all costs and all revenues are considered simultaneously, a DSIC is a one-way street that can only increase rates between rate cases, even if a utility's other costs are going down or its revenues are going up. In setting utility rates, it is important to look at all the utility's costs and revenues, not just a single utility cost item that may be added between rate cases.

While I strongly oppose the enactment of a DSIC, I would respectfully urge the General Assembly to consider a number of amendments to House Bill 744 in the event that the General Assembly chooses to go forward with this legislation.

First, I would suggest that the DSIC should only reflect the net increase in distribution plant between rate cases; that is, the cost of new capital additions in the relevant categories, minus the depreciation and retirements from the same categories of plant during the same time period. In that way, if a natural gas utility is truly making substantial new capital additions that exceed the normal reductions in plant value that occur between rate cases, then the company can charge the customers a positive DSIC. Second, there should be a percentage cap on the total level of DSIC rate increases, and that cap should be based on the utility's distribution revenues, not on total revenues, which include highly volatile natural gas commodity costs that are not related in any way to the distribution system improvements. I would suggest that the cap be set at 5%, which is where the PUC initially set the cap for the water DSIC's, but which the Commission subsequently allowed Pennsylvania American Water Company to increase to 7.5%. Third, I would propose that any natural gas DSIC be preceded by a full base rate case in which the company's total costs and revenues would be examined by the PUC before any automatic increases are permitted. In that way, a utility that has not filed a base rate case in 15 years could not simply walk in to the Commission and start increasing its rates every three months without any prior examination of whether its current rates are just and reasonable.

In order to assist the members of this Committee I have attached three amendments to this testimony that I believe would address these issues. As always, I would be pleased to work with the members and staff of this Committee to develop legislation that I hope would best serve Pennsylvania's utility consumers.

Thank you again for permitting me to testify at this hearing. I would be happy to answer any questions you may have at this time.

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AMENDMENTS TO HOUSE BILL NO. 744

Printer's No. 830

Amend Section 2, page 2, line 25, by inserting after "of"

the net change in

Amend Section 2, page 2, line 30, by inserting after "proceedings"

, minus any decreases in net distribution plant resulting from depreciation and retirements of the same categories of existing distribution plant during the same period.

Amend Section 2, page 3, by inserting between lines 4 and 5

(3) The revenue collected in any year pursuant to an automatic rate adjustment mechanism established pursuant to this subsection shall not exceed five percent of the amount a natural gas distribution company billed its customers for distribution service in the previous calendar year.

Amend Section 2, page 3, line 4, by inserting after "mechanism"

The commission shall include as part of that regulation or order a requirement that a natural gas distribution company shall not initially establish an automatic rate adjustment mechanism pursuant to this subsection unless the commission has established the natural gas distribution company's rates in a general rate case as set out in section 1308(d) (relating to voluntary changes in rates), filed after the effective date of this subsection.

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ATTACHMENT C

Increasing Use of Surcharges on Consumer Utility Bills

PREPARED BY LARKIN & ASSOCIATES, PLLC FOR AARP | MAY 2012

AARP®

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EXECUTIVE SUMMARY

For many consumers, home utility bills are becoming more and more cluttered with new fees and surcharges to pay for everything from the investment in new gas pipelines to environmental compliance costs. The imposition of these surcharges are a departure from the traditional utility rate setting process, and regulators need to carefully evaluate utility requests for additional surcharges on a case-by-case basis to determine whether there is a proper balance of meeting utility needs and assuring ratepayer protections.

A surcharge is an additional fee imposed on a ratepayer's utility bill in addition to the base rate charge for utility service. In the past, surcharges were only approved by regulators in rare circumstances to address substantial, volatile and uncontrollable costs that, if *not* addressed outside of a base rate case, could threaten to harm a utility's financial health. Examples of such surcharges include fuel and purchased power adjustment mechanisms for electric utilities and gas cost recovery mechanisms for natural gas distribution utilities. In recent years, however, requests for other types of surcharges and tracking mechanisms by utilities have significantly increased.[1] Indeed, the National Regulatory Research Institute characterizes the use of cost trackers and mechanisms as the "latest trend."[2]

Utilities have requested surcharge rate mechanisms as a means to accelerate the recovery of a variety of costs, many of which are not volatile or uncontrollable. In some instances, the use of surcharges and other tracking mechanisms have proliferated so as to be baffling and expensive for consumers and burdensome for regulators to monitor.

Utilities say the surcharges are needed so they can make investments in aging infrastructure and comply with environmental regulations, among other claims, without compromising their financial health. Utilities also claim that the surcharges will result in smaller and less frequent rate increases as well as reduce the frequency of their general rate cases, which can be time consuming and costly to process.

But the increasing imposition of surcharges and other alternative ratemaking mechanisms can also defeat some of the primary principles of the rate-setting and regulatory review process. Besides increased costs to consumers, surcharges can also result in such additional undesirable consequences as reducing utility incentives to control costs and shifting utility business risks away from investors and onto customers.

Regulators need to carefully evaluate utility requests for additional surcharges on a case-by-case basis to determine whether there is a proper balance of utility and ratepayer needs. If the regulator decides to approve a utility's request to impose new surcharges on ratepayers, adequate safeguards to protect consumers are a must.

INTRODUCTION

For many consumers, home utility bills are becoming more and more cluttered with new fees and surcharges to pay for everything from the investment in new gas pipelines to environmental compliance costs. Not only are these charges often confusing and frustrating to consumers, they also represent a shift from the traditional utility ratesetting process. A surcharge is an additional cost added to utility customers' bills. Surcharges are also referred to by other terms such as riders, adjustment clauses, recovery mechanisms, and cost trackers. The proliferation of additional fees and surcharges generally shifts risks away from utility investors and onto consumers. This report describes why consumers should be concerned about the shift toward utilities collecting more costs outside of the traditional rate structure. Descriptions of some types of fees and surcharges proposed and/or collected by the nation's major utilities are outlined in Appendix I of this report.

HOW FEES AND SURCHARGES DIVERGE FROM THE TRADITIONAL METHOD OF SETTING UTILITY RATES

Utilities must petition state regulators to increase utility rates. Utilities submit a formal request to regulators containing their proposed rates to charge customers. The utility's request is reviewed in a formal proceeding, which is called a "rate case." Interested parties, such as representatives of residential or business customers, are allowed to intervene and review the utility's documentation to determine if the utility's request is reasonable. The case is resolved by a hearing and the regulators issue a formal decision.

The utility's requested rate is called a "revenue requirement" which is the amount necessary for the utility to cover its financial obligations associated with providing safe, reliable service to customers, along with earning a reasonable "return." Basic accounting and ratemaking principles serve as the foundation in setting rates to be charged by utilities to provide safe, reliable service. The primary purpose of utility ratemaking is to establish rates that allow a utility to recover its prudently[3] incurred operating and maintenance expenses, plus a fair return on its investment in assets that are used and useful[4] in providing utility service. Rates are calculated based on a "test-year" which is a 12-month period to be representative of operating conditions when the rates being established will be in effect.[5] Utilities are generally required to "net" all costs and benefits of operation at the time rates are set to avoid "cherry-picking" individual cost increases that may be offset by other cost decreases.[6] Under traditional ratemaking, utilities cannot change rates charged to customers outside of a rate case.[7]

Consumers are most familiar with seeing the "base rate" charge on their bills. The base rate is defined as the rate gas and electric utilities charge customers for the cost of providing safe and reliable service, which includes an opportunity for the utility to earn a fair return on its prudently incurred utility plant investment. The base rates are set by state regulators in a rate case, and are often segregated between the basic service charge, distribution, transmission and, for electric service, generation.[8]

In addition to base rates, most utilities assess a fuel surcharge (gas cost adjustment or fuel and purchased power adjustment) and revenue-based taxes in addition to the base rate charge. Typical "standard" charges that appear on a customer's electric utility bill may include:

- Customer Charge: The basic charge to recover costs for billing, meter reading, equipment, maintenance, etc. (state regulated)

- Generation Charge (or Commodity Charge): Charges for the production of electricity, based on usage (state regulated in non-deregulated states)

- Transmission Charge: Charges for moving high voltage electricity from a generation facility to the distribution lines of an electric distribution company [regulated by the Federal Energy Regulatory Commission ("FERC")]

- Distribution Charge: Charges for the use of local wires, transformers, substations, and other equipment used to deliver electricity to end-use consumers from the high voltage transmission lines (state regulated, only shown as a separate charge in deregulated states)

- Fuel and Purchased Power Charges
- State Taxes

Typical standard charges that appear on a customer's gas utility bill may include:

- Customer Charge
- Gas Transmission or Distribution charge
- Commodity Charge
- Purchased Gas Adjustment (true-up)
- State Taxes

Other fees and surcharges fall into the category of "single issue ratemaking," which is a deviation from traditional ratemaking. Single issue ratemaking involves "singling out" specific expenditures from a company's base rates and allowing a utility to separately recover those costs from ratepayers. Singling out specific costs can make the traditional ratemaking formula unbalanced. For example, if a utility replaces a large piece of equipment at its plant, the new equipment will affect multiple aspects of the business. The utility's rate base plant will increase, and revenues may increase, if the plant addition is to serve new customers. Future maintenance expenses may decrease if the addition improves efficiency. The lower maintenance costs, which would reduce rates for ratepayers, may not be reflected within a surcharge that focuses only on the new investment.

In the past, single issue ratemaking was typically approved by regulators only in limited situations for costs that were considered:

1. Largely outside the control of the utility,
2. Unpredictable and volatile, and
3. Substantial and reoccurring, and which would have the potential to adversely impact the utility's financial health if cost recovery is not addressed outside of a traditional rate case.

Examples of such volatile and unpredictable costs traditionally include fuel costs and purchased power costs for electric utilities, and purchased gas costs for gas utilities. In contrast, capital investments for plant additions or replacing aging infrastructure are not generally considered to be highly volatile, uncontrollable and/or unpredictable. Management can control these costs to some extent by comparison shopping materials and contractors. The timing of projects can also be adjusted based on availability of funds.

Yet in recent years, many other types of costs are being proposed by utilities to be recovered through surcharges that do not meet the above criteria.[9] The National Regulatory Research Institute characterizes the use of cost trackers and mechanisms as the "latest trend."[10]

Allowing a utility to recover lost revenues or discrete increased costs through a surcharge can also diminish the utility's incentive to control or reduce expenses because the utility is assured of full cost recovery. Since the utility is passing the cost on to customers, it has less incentive to seek ways to reduce the expense. Furthermore, in a rate case, the utility's costs are carefully scrutinized, whereas cost increases recovered in surcharges can become part of utility rates on an expedited basis, without being subjected to the same degree of review. In rate cases, utilities must provide documentation justifying its requested costs or they may be disallowed. Reviews of costs recovered via surcharges are usually done on a much more limited basis. By allowing a utility to recover cost changes through a surcharge, rider or balancing account, the utility is assured of the recovery of such costs, therefore diminishing the utility's incentive to control expenses, and reducing the utility's financial risk.

SURCHARGES, TRACKERS AND OTHER COST RECOVERY MECHANISMS

DEFINITIONS

There are different types of "single issue ratemaking" which include surcharges, trackers, riders, and other cost recovery mechanisms.[11]

Surcharge: A surcharge allows a utility to separately charge customers for costs that would have otherwise been part of the utility's standard base rates. This means the utility recovers dollar-for-dollar the level of costs incurred or estimated to be incurred. A surcharge appears as an additional charge on a ratepayer's utility bill, above and beyond the base rates, fuel surcharge and taxes. Some surcharges are a flat rate while others fluctuate, either based on usage or changes in the surcharge rate.

Surcharges are also referred to as riders, adjustment clauses, recovery mechanisms, and cost trackers, etc. Many utilities use the term "rider" in their tariffs with respect to surcharges. However, some utilities use the term "rider" to designate rates for a particular class of service. For example, Georgia Power defines "rider" as a modification to an existing tariff rate.[12] In these instances the "rider" is a type of rate on a customer's bill associated to that type of specific utility service, rather than an additional "surcharge". Therefore, one must read the Company's applicable tariff sheet to understand what the rider or surcharge actually represents. Utility tariff sheets may be written in technical language, and this may be hard to understand for many consumers.

Sometimes the entire cost recovered by a surcharge is excluded from base rates and recovered separately through the surcharge (e.g., fuel costs). In other instances, only the incremental portion or the difference between what is included in the base rates and the changes in the cost (e.g., in some states vegetation management or storm damage costs) are recovered through the surcharge. For instance, if a utility is allowed to recover $10 million in base rates for tree trimming expenses, but actually spends $11 million, and the utility has a surcharge mechanism in place for such costs, the $1 million difference would be assessed as a surcharge to ratepayers.

A surcharge can either be a fixed rate or adjusted periodically as the cost element it covers changes (i.e., monthly, quarterly or annually). Changes in costs addressed by the surcharge are typically reviewed by regulators periodically (e.g., annually or quarterly). However, the level of review of utility costs charged to customers through surcharges is usually more informal, expedited and less rigorous than in contrast to the in-depth review that would typically be conducted in a full utility rate case.

For example, in a recent utility case in Nebraska the utility requested three adjustment mechanisms (weather normalization, a billing adjustment factor and an inflation factor). However, the state regulator denied the surcharges:

> Such automatic mechanisms can lead to excessive rates, an inappropriate shifting of risks from stockholders to ratepayers, and decreased incentives to operative efficiently.
>
> ...
>
> Therefore the rate mechanisms should be denied.[13]

Balancing Accounts: Another form of single issue ratemaking, referred to as "balancing accounts," also can result in new surcharges on bills for utility service. A balancing account tracks the difference in a certain cost allowed in base rates and the actual cost.[14] California is one state regulatory jurisdiction that makes extensive use of balancing accounts.[15] The ratemaking regime in California has become particularly complex. The extensive use of balancing accounts and cost trackers has made it challenging and difficult for the regulators to adequately audit the proliferation of special mechanisms being used by utilities. California utilities have a traditional three-year General Rate Case ("GRC") cycle, though the cycle has been extended beyond that in some instances. The utility's base rates are developed using forecasted amounts and typically are adjusted annually for inflation. An added complexity is that many issues affecting the utility's base rates may also be addressed separately in other dockets. The California utilities also utilize a variety of mechanisms to recover costs separately from base rates: surcharges, adjustment mechanisms, balancing accounts and memorandum accounts.[16]

Some believe that the use of balancing (and memorandum accounts) by California utilities has become excessive. A recent California American Water Company ("CalAm") General Rate Case demonstrates how the use of surcharges and other alternative rate mechanisms can get out of control. In Application No. A.10-07-007, CalAm had 79 existing balancing and memorandum accounts. CalAm had requested six additional balancing and memorandum accounts, which if approved, would bring the total to 84. The Department of Ratepayer Advocates ("DRA"), which is charged with looking out for the consumer interest, acknowledged that it did not have the resources to fully review the Company's numerous accounts:

> These advice letters are generally approved without audit. There is little opportunity to review the recorded amounts for reasonableness before the balances are recovered, unless DRA requests the opportunity to audit the balances or request for a suspension of the advice letter.[17]

Exhibit 1 is a table summarizing the number of balancing and memorandum accounts utilized by some of the larger California utilities:[18]

EXHIBIT 1

UTILITY	BALANCING ACCOUNTS	MEMO ACCOUNTS	OTHER ACCOUNTS	TOTAL
Southern California Edison (SCE)	21	24	16	61
Southern California Gas Co. (SoCal)	22	24	10	56
San Diego Gas & Electric (SDG&E)	22	33	7	62
Pacific Gas & Electric (PG&E)	32	35	15	82
California American Water Company	*	*	*	79
Golden State Water Company	9	29		38
Total Accounts for Regulators to Review	106	145	48	299

* Information regarding the breakdown of the different accounts was not located; as noted above, CalAm's requests, if approved, would increase the total to 84.

Trackers: Another single issue ratemaking mechanism is a "tracker" which involves recording or "tracking" costs in a specified account, which are later reviewed by regulators. The costs are not initially included in the utility's base rates, but are accumulated or "set aside" for future review. They may be incorporated into the development of the utility's base rates in its next base rate case or may show up as a separate charge on ratepayers' bills. This type of mechanism is sometimes utilized to "track" whether the authorized level is being spent. In some situations, underspending by a utility of a "tracked costs" is eventually returned to ratepayers.

An example of utility expenses that have been "tracked" are vegetation management (tree trimming) costs. For example, a utility may have issues with its reliability and regulators may decide to monitor the level of the utility's tree trimming expenditures as a means of assessing whether the utility is conducting an adequate level of maintenance near its wires and poles.

Another example of a cost that has been "tracked" and deferred by a utility for future review are storm damage costs. A utility may incur substantial repair costs to its distribution system as a result of a catastrophic storm. Some utilities have petitioned regulators to accumulate and defer the extraordinary storm repair costs for review and inclusion in rates at a later date, rather than merely recording such costs as expenses in the current period, which may result in utility investors bearing the risk of such costs if they result in the utility reporting lower earnings for that accounting period.

Depending on the definition of "tracker" in a particular jurisdiction, by allowing a utility to recover costs through a tracker account, the utility may effectively be guaranteed recovery of the tracked expense. Sometimes the deferrals are limited to a pre-specified level; in other cases, the subsequent recovery by the utility of the tracked cost may be subject to an "earnings test". An earnings test may prevent the utility from subsequently charging all of the tracked/deferred costs to ratepayers if it would result in excess earnings.

SURCHARGES HAVE BEEN IMPOSED THROUGH REGULATION AND LEGISLATION

A utility must obtain permission from its state regulator to apply an additional surcharge to customers' bills. Typically, a utility will present the mechanics for its proposed surcharge to the regulator for approval. Consumer advocates and intervenors may participate in the proceeding and make recommendations to adjust or modify the utility's proposal. The regulator will weigh the information and make its decision. Again, if a surcharge mechanism is approved, there are time and resource limits to the review of the costs, making it difficult for intervenors to participate. Once cost categories are approved for recovery in a surcharge, the categories can no longer be questioned, and the only aspect that can be disputed is whether the level of such costs are reasonable and prudently incurred to provide utility service. Some jurisdictions allow use of surcharges consistently between utilities, while others approve surcharges on a case-by-case basis.

In several states, surcharges have been adopted through legislation, often requiring the use of a surcharge and limiting the discretion of regulators. An example of where legislation now limits what the state utility regulatory commissions can do is the state of Virginia. Virginia has passed legislation allowing utilities to recover many types of costs through surcharges, including environmental costs, costs for constructing new generation, generation and demand side management, and other types of costs.

In Utah, legislation has been passed allowing gas or electric utilities to recover the costs of major plant additions by filing an application for approval of a major plant addition within 150 days from the capital addition's scheduled in-service date. The statute defines "major plant addition" as "any single capital investment project of a gas corporation or an electrical corporation that in total exceeds 1% of the gas corporation's or electrical corporation's rate base."[19]

On October 26, 2011, the Illinois legislature overrode the Governor's veto of Senate Bill 1652, which became effective as Public Act 97-0616. Among those changes was the addition of a new Section 16-108.5 entitled "Infrastructure Investment and Modernization; Regulatory Reform." This legislation provides for utilities to file for a performance based formula rate plan process. On November 8, 2011 Commonwealth Edison Company, the state's largest utility, filed for a new tariff called Rate DSPP (Delivery Service Pricing and Performance), pursuant to that legislation. A formula rate plan is a mechanism or "formula" which resets a utility's rates annually, and is used in place of a rate case.

Due to the utility mergers and acquisitions over the years, many local utilities are now subsidiaries of large holding companies that have utility operations in multiple state jurisdictions. These large corporations have the resources to effectively lobby their positions to benefit their operations.

American Electric Power Company ("AEP"), one of the nation's largest electric utilities, affirms this by stating in its 2010 Form 10-K:

> Given the long lead times in construction, the high costs of plant and equipment and difficult capital markets, we are actively pursuing strategies to accelerate rate recognition of investments and cash flow. AEP representatives continue to engage our state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process.

As another example, Xcel Energy, stated in its 2010 Form 10-K that:

> Xcel Energy files periodic rate cases and establishes formula rate or automatic rate adjustment mechanisms with state and federal regulators to earn a return on its investments and recover costs of operations.

A utility's proposal for cost recovery under the legislatively authorized mechanisms are typically reviewed via the regulatory process, albeit on a limited basis, as described above. The review may be primarily performed by utility commission staff as active participation in reviewing a proliferation of utility surcharges by resource constrained consumer advocate groups is difficult to sustain.

Exhibit 2 is a table summarizing types of costs utilities are charging customers through surcharges. This is not a comprehensive listing, but rather a summary to illustrate various types of surcharges that were identified in the process of preparing this report.

EXHIBIT 2: EXAMPLES OF SURCHARGES

DESCRIPTION	STATES
Aging infrastructure	GA, KY, MO, NJ, OH
Decoupling/Weather Normalization	CA, GA, KS, KY, LA, MD, MS, NJ, NV, TN, TX, VA
Energy Efficiency/DSM/Conservation	CA, OR, MD, MA, SC, NC, IN, AR, KY, MI, OH, OK, TX, CO, IA, GA, FL, IL, MO
Environmental Compliance	WA, DE, NJ, IA, IN, KY, MN, SD, MI, OH, TN, TX, VA, GA, NJ, IL
Franchise Fees	MN, TX, AR, KY, LA, MI, VA, WV, GA, NJ, TN, IL, CO
New Plant (Coal, Nuclear)	AL, AR, GA, IN, MS
Pension/OPEB	MA, SC
Property Taxes	KS, MS
Renewable Energy	IL, NC, OH, MA, CA, IA, OR, UT, WA, CO, MN, NM
Smart Meters/Smart Grid	CO, OH, TX
Storm Damage	MA, OH, OK
Stranded Costs	CT, NH, NJ, MA
System Reliability/Vegetation Management	KS, OH, OK, TN, TX
Transmission Investment	OH, TX, VA
Uncollectibles	IA, IL, OH, NV
Universal Service/Low Income	AZ, CA, CO, DC, TX, GA, IL, OH, OR, UT, WA, MD

WHY DO SURCHARGES, RIDERS AND ADJUSTMENT MECHANISMS PUT CONSUMERS AT RISK?

In many instances surcharges are unnecessary and are not beneficial to ratepayers. Surcharges are costs added to utility customers' bills in addition to the basic charge for providing safe and reliable utility service. Surcharges can effectively guarantee utilities recovery of their fluctuating costs, thereby, shifting financial risk away from the investors and onto consumers. The surcharge is often applied to consumers' bills without first being subject to a thorough review by regulators and consumer groups. Additionally, some surcharges may recover costs that are not necessary for providing basic safe and reliable service. Surcharges may put consumers are at risk for being overcharged by utilities for basic utility service.

Reasons why surcharges pose a risk for consumers include:

REDUCES THE UTILITY'S INCENTIVE TO CONTROL COSTS

In a rate case a utility is allowed a reasonable level of revenues to recover its operating expenses as well as an opportunity to earn a fair return on its prudently incurred investment in used and useful plant. In between rate cases, the benefit of any cost reductions would flow back to the utility as higher profits. For costs that are to be "tracked" through a surcharge, the utility is usually required to return any under-spending to ratepayers, so the utility is not benefitted by cost-cutting efforts. The surcharge can thus remove or reduce the utility's incentive to reduce costs. Guaranteeing recovery of a specific expense reduces the utility's incentives to control costs, and thus shifts the burden of cost increases between rate cases from shareholders onto ratepayers.

REVIEW OF SURCHARGES IS TYPICALLY MORE LIMITED

Utilities typically submit reports to regulators for costs recovered via a surcharge on an annual or quarterly basis. This usually involves submitting some calculations and workpapers identifying and supporting the amounts. The review by regulators is typically conducted on an expedited basis, as opposed to the thorough review that would typically occur in a full rate case. In rate case, a thorough review of costs can also be conducted by intervening parties, and the utility must adequately support its costs or they risk being disallowed.

VIOLATION OF THE MATCHING PRINCIPLE, A FUNDAMENTAL ACCOUNTING AND RATEMAKING PRINCIPLE

A key concept in accounting and ratemaking is the matching principle. The matching principle involves matching revenues with related expenses and investments in the time period they occur. Accounting and ratemaking require the cost of capital investments to be spread over the period in which they will be used. Capital investments, such as replacement of equipment at the utility's plant can produce efficiencies such as reducing future O&M costs or enable new revenues. If the cost of the capital expenditure is recovered through a surcharge, these efficiencies may not be captured in the surcharge. Recovering capital investments via a surcharge can thus violate the matching principal.

UTILITY MAY OVER-COLLECT THESE COSTS

In some cases, the utility may overestimate the costs to be recovered. Therefore, it may over-collect these costs from ratepayers. For example, if a utility collects a surcharge to fund the cost of a new plant or a large piece of equipment while it is still being constructed, the amount being collected from customers may be more than the actual cost. While the funds should ultimately be returned to ratepayers, until then, these funds can be used by the utility and represent a source of cost-free capital to the utility.

For example, San Diego Gas & Electric Company stated in its current 2012 general rate case ("GRC"), in its direct testimony, that its Advanced Metering Infrastructure Balancing Account (AMIBA) was forecasted to be $48.546 million overcollected on the electric side and $6.33 million overcollected on the gas side at December 31, 2011. This means that the utility collected $54.876 million more from customers than it needed. The Company also stated that it forecasted its Distribution Integrity Management Program Balancing Account (DIMPBA) and Research Development & Demonstration Expense Account (RDDEA) to be over-recovered by $3.304 million and $0.191 million, respectively. The RDDEA was authorized in D. 08-07-046 and went into effect on January 1, 2008. The Company was collecting the surcharge from customers for most of the year; however, the Company stated the related R&D program spending did not begin until late in 2008.[20]

There is also the risk that overpayment of costs may be not be returned to customers, because if the surcharge costs are reviewed only on a cursory basis, any errors or overcharges may not be detected and/or returned to customers.

JUSTIFICATIONS FOR SURCHARGES DO NOT HOLD UP

Below are some reasons utilities may use to justify the use of surcharges, along with a comment concerning why the reasoning may be invalid.

FREQUENCY OF GENERAL RATE CASES

Utilities may cite reduced frequency of general rate cases, which can be costly to litigate, as a reason for surcharges. The purpose of general rate cases is to thoroughly evaluate the utility's rates and costs for reasonableness. Eliminating or bypassing that opportunity to review the utility's costs may result in costs being charged to ratepayers without adequate regulatory scrutiny. Implementation of surcharges may also result in burdening regulators with additional work, as they will need to review these surcharges between general rate cases.

"RATE SHOCK"

Utilities will sometimes argue that surcharges and trackers reduce "rate shock" because the surcharge produces smaller, more frequent rate increases, rather than a future sharp hike in rates from a base rate case. In a rate case, many factors comprise a utility's base rates: capital structure, capital investments, and operating expenses. While some costs may increase, they could be offset by decreases in other expenses. A rate case review may not necessarily result in a rate increase. A utility may be found to be over-earning and rate decrease may be ordered. Therefore, one cannot assume that utility base rate cases will always result in larger rate increases.

AGING INFRASTRUCTURE

Many utilities have requested surcharges to recover the costs of investments to upgrade aging infrastructure. However, utility capital expenditures are not volatile or outside the control of a utility. Management is able to influence the timing and extent of these costs. Utilities, similar to other non-regulated companies, issue bids for large scale projects to evaluate the most cost-effective options. Maintaining and upgrading the utility infrastructure is a normal aspect of operating a utility. Also, cost efficiencies may result from the improvements, but such savings may not be recognized as an element that reduces the surcharge.

COMPLIANCE WITH ENVIRONMENTAL REGULATIONS

Similarly, a utility might cite expenditures that it must make to comply with environmental regulations as a reason to implement a surcharge. This is not a new concept. Environmental regulations have been in existence for many years and are continuously evolving. Complying with environmental regulations is also a normal aspect of operating a utility. How best to deploy capital and O&M resources to comply with these regulations is not entirely outside the control of a utility. Also, cost efficiencies associated with the environmental investment may not be recognized as an offsetting element that reduces the surcharge.

SITUATIONS WHERE TRACKING MECHANISMS BENEFIT CUSTOMERS

There have been limited situations where surcharges have benefited customers. As one example of this, in the 1980s, Entergy implemented a return sharing mechanism in Arkansas which was primarily weather driven. The effects of the hot summer weather that had not been captured in the base rate case generated higher revenues for the Company and customers received credits on their bills.

RECOMMENDED CONSUMER SAFEGUARDS

When regulators are considering whether to allow certain expenditures to be recovered via a surcharge or other special rate mechanism the following consumer protections should be considered, and included, if a surcharge is approved:

COST RECOVERY SHOULD BE SPECIFIC

If a surcharge is approved, it should be strictly for the specific expenditure. The surcharge should not contain multiple types of costs or be vaguely defined, which will make reviews difficult. The surcharge should not be allowed to be expanded at a later date to include additional items. As an example, of surcharge coverage expansion, Atlanta Gas Light was permitted to implement a pipeline replacement surcharge to recover costs associated with implementing an aging pipeline replacement program over a ten year period. The need to replace aging pipe to address safety issues resulted from an investigation of the utility's alleged violations of minimum federal safety standards. Years later, the utility proposed and was allowed to expand this surcharge to include other types of capital costs associated with installing new distribution pipeline and infrastructure upgrades that were not strictly related to addressing the public safety concerns that were the basis for allowing the original surcharge.

NUMBER OF SURCHARGES SHOULD BE LIMITED

A utility should not be permitted to have a complex myriad of surcharges and trackers. This defeats the purpose of reducing rate cases and the rate setting process in general and places a bigger burden on the regulator to have to monitor numerous surcharges outside of rate cases.

The extensive use of surcharges, trackers, memorandum accounts, and other recovery mechanisms by California utilities has resulted in an almost overwhelming burden on regulators and consumer advocates.

TIME PERIOD OF SURCHARGE SHOULD BE DEFINED, NOT INDEFINITE

The surcharge or tracker should be for a set time period rather than indefinitely. For example, some states have implemented revenue decoupling as a pilot. After the pilot period, regulators can then review the results to determine the cost-effectiveness of implementing the special rate mechanism and determine whether it should continue.

MECHANICS OF SURCHARGES SHOULD BE STRUCTURED TO BENEFIT THE RATEPAYER

The surcharge should be structured so that cost overruns are absorbed by the utility and underspending is returned to ratepayers. Some of the utility cost tacking accounts used by California utilities have this feature. A "one-way" balancing account, for example tracks and returns utility under-spending for the tracked cost (such as tree-trimming) to ratepayers.

RELATED COST SAVINGS AND EFFICIENCY IMPACTS SHOULD BE INCORPORATED

If the surcharge is to recover costs associated with replacing plant equipment, or for investments which improve efficiency, an efficiency factor to reflect lower O&M costs should be considered.

LOWER RETURN ON EQUITY ("ROE") TO REFLECT REDUCED RISK

A utility's ROE is the return investors expect, or require, in order to invest in the Company. In a rate case, utilities request a specific ROE percentage which is reviewed by the parties and a fair and reasonable ROE is authorized by the Commission. While a utility's ROE is based on several factors, depending on the utility's specific circumstances, a reduction in ROE may be appropriate if a surcharge is approved. A portion of the Company's business risk has been transferred from investors and is now being borne by ratepayers.

REDUCE FREQUENCY OF RATE CASES

Many utilities allege that surcharges will reduce the frequency of rate cases or large rate increases. A possible condition for approving a surcharge could be that the utility agrees to not file for a base rate increase for a specified period. Conversely, if a utility has annual rate cases or multi-year rates, a surcharge may not be necessary as the utility's rates are already being adjusted more frequently.

AVOID APPROVAL OF NEW SURCHARGES IN A SETTLEMENT

Although settlements are typically non-precedential (i.e., non-authoritative) if a surcharge is approved in a settlement, it may be unlikely or difficult to have it reversed or denied in future proceedings. Also, other utilities may imitate and cite the use by the existing utility as justification for their proposed surcharges for similar costs.

AUDIT/REVIEW FOR PRUDENCE AND REASONABLENESS

If a surcharge is approved to recover costs associated with a substantial project such as construction of a new power plant, significant environmental retrofits, or Smart Grid, a recommendation could be made that a full audit or a detailed review of the prudence and reasonableness of the costs should be conducted. For example, the Mississippi PSC is conducting a prudence review of the costs associated with Mississippi Power Company's (MPCo) Integrated Coal-Gasification Combined Cycle ("IGCC") Plant that is currently under construction in Kemper County. MPCo is proposing to recover the Construction Work In Progress ("CWIP") financing costs associated with the Kemper Project through a surcharge.

RECENTLY PROPOSED SURCHARGES THAT HAVE BEEN DENIED

Regulators are still relying on traditional ratesetting and have not been persuaded by utilities' requests to implement surcharges. Below is a brief discussion of some recent instances:

PENSION/OTHER POST RETIREMENT BENEFITS (OPEB)

Narragansett Electric (d/b/a National Grid), Rhode Island; Docket No. 4065 (2010). The Company proposed a mechanism to recover pension and other post employment benefits expense incurred each year over the amount included in base rates. The Rhode Island Commission denied Narragansett's request. The Order stated:

> ...the Commission finds that this expense is a business risk that should be managed by the Company like any other business risk facing a business enterprise. Also important to note is that the State of Rhode Island, whose pension fund is severely underfunded, has not proposed that the Rhode Island taxpayers be burdened with a reconciling mechanism to ensure adequate funding of the state pension program. The General Assembly has proactively modified the existing plan to address this underfunding by changing the benefit eligibility, increasing the level of employee contributions, among other options under consideration.

Delmarva, Maryland; Docket No. 9093 (2007). The Company requested a Pension and Other Post-Employment Benefits ("POPEB") rider, to capture yearly differences between the pension and OPEB costs embedded in the Company's base rates and the actual expenses properly chargeable to the Company's distribution operating costs. The Maryland Commission denied the Company's request. The final Order stated:

> Implementation of a tracker mechanism is an extraordinary form of ratemaking usually reserved for very large expense items that have the potential to impair seriously a utility's financial well-being, which is not the case here for OPEB and pension costs. We therefore deny the Company's request for a POPEB rider.

Delmarva, Delaware; Docket No. 09-414 (2011). Delmarva proposed a surcharge mechanism called a Volatility Mitigation Rider ("Rider VM") to collect a rolling three-year average of pension, OPEB and uncollectible expenses, which it claimed were volatile and largely beyond its control. The Delaware Commission denied the Company's request and stated in its Decision:

> These are normal utility expenses; allowing dollar for dollar recovery of them would depart from traditional ratemaking practices and would reduce Delmarva's incentive to try to control them. We also note that our sister commissions in Maryland and

> the District of Columbia rejected the same proposal when Delmarva and its affiliates presented it to them, and we find their reasoning convincing. Thus, for the reasons advanced by Staff and the DPA, we reject Delmarva's request to implement Rider VM.

ENVIRONMENTAL COMPLIANCE COSTS

Kansas City Power & Light, (KCPL) Case No. 11-KCPE-581-PRE (2011)

KCPL requested recovery of environmental upgrade costs at its La Cygne Plant through a surcharge. The Commission's decision to deny the surcharge was based in part on an observation that "the potential future cost that utility companies will undoubtedly expect customers to bear is presently unforeseeable or speculative at best, but undoubtedly will be significant."

DECOUPLING

Many utilities have claimed that they require "revenue decoupling" in order to eliminate disincentives which prevent them from vigorously promoting energy-efficiency.

Despite the utility industry's attempt to convince regulators that decoupling is the latest concept, several states are still reluctant to implement decoupling mechanisms.[21] For example, Connecticut denied two utilities' requests for decoupling, despite legislation enacted permitting decoupling (Connecticut Light & Power; Docket No. 09-12-05; 2010, and Connecticut Natural Gas; Docket No. 08-12-06; 2009).

The following states have also rejected decoupling mechanisms:

- Indiana, Southern Indiana Gas; Cause No. 43839 (2011)
- Montana, Northwestern Energy; Docket No. D2009-0-129 (2011)
- Tennessee, Piedmont Natural Gas; Docket No. 09-00104 (2010)
- Rhode Island, Narragansett Electric (d/b/a National Grid), Docket No. 3493 (2009)

In the above cases, the regulators decided to reject decoupling because benefits to customers were speculative and the risk was shifted away from the company and onto customers.

Notably, the regulator's order in the Narragansett case stated:

> Revenue decoupling would protect the Company from revenue declines attributable to any causes, not only conservation and efficiency efforts. . . . Over the last four years, decoupling would have resulted in an additional $34 million payment to the Company.

One of the concerns about decoupling is that it insulates utilities from economic conditions such as the impacts of a recession. As Dr. David Dismukes has explained:

> Decreases in sales associated with economic downturns have nothing to do with energy efficiency programs offered by the Company. Instead, they are the natural reaction of households trying to reduce their expenditures during difficult economic times of, or alternatively, businesses and industries idling or shutting down their operations. Under revenue decoupling, ratepayers would be required to make a utility whole for

revenue losses during these economic downturns, whereas under traditional regulation, utilities bear the risk of these economic contractions, just like many other types of businesses and industries.[22]

On January 26, 2009, Detroit Edison Company ("DTE") filed an application with the Michigan Public Service Commission ("MPSC"), Case No. U-15768. Among other things, DTE requested that the MPSC approve an electric rate decoupling mechanism and an advanced metering infrastructure ("AMI") program. Both of those requests were approved by the MPSC in its January 11, 2010 order. On April 10, 2012, DTE's electric rate decoupling mechanism and the AMI program funding mechanism were rejected by the Michigan Court of Appeals.[23] The Court ruled that the MPSC did not have the authority to direct or approve decoupling for electric utilities, but only had authority to conduct research and report on the operations of a decoupling mechanism with electric utilities. Michigan Statute MCL 460.1097(4) states that:

> [T]he commission shall submit a report on the potential rate impacts on all classes of customers if the electric providers whose rates are regulated by the commission decouple rates. . . . The commission's report shall review whether decoupling would be cost-effective and would reduce the overall consumption of fossil fuels in this state.

The Court also ruled that DTE's AMI program funding that had been approved by the MPSC "was unreasonable, because it was not supported by 'competent, material and substantial evidence on the whole record'".[24] The Court noted that the Manager of the Energy Efficiency Section in the Electric Reliability Division of the MPSC had agreed that the AMI was not commercially tested, and required large amounts of capital, which could result in great economic risk and highly impact rates. No alternative considerations were discussed, nor were the needs for AMI or the net-benefits (if any) to the affected customers. The Court also stated that in reviewing the MPSC's decision, it "will not rubber stamp a decision permitting such a substantial expenditure—a cost to be borne by the citizens of this state—that is not properly supported."[25]

CAPITAL ADDITIONS

In New Mexico, in a 2011 decision, the commission rejected a stipulated capital additions rider for Public Service New Mexico Company, stating such a rider would represent "a major departure from and violation of the Commission's long-standing policy against piecemeal ratemaking."

In a recent Washington Gas Light Company ("WGL") rate case (Case No. 9267) the Maryland Public Service Commission's order issued on November 14, 2011 rejected WGL's request for an automatic surcharge on all customers to improve its distribution system. In denying that request, the Commission found that WGL was capable of carrying out a pipeline replacement program and ensuring the safety and reliability of its distribution system without getting automatic cost recovery through a surcharge:

> Although we agree fully with the Company that safe and reliable infrastructure is its highest priority and that it should accelerate its program to replace pipe, we decline to authorize a surcharge for the recovery of future pipe replacement expenses. Based on the record in this case, we find that the Company has historically demonstrated the ability to replace its

infrastructure when necessary to ensure safety and reliability, and that it can do so using traditional ratemaking procedures without compromising its ability to earn an appropriate return. The Company's witnesses confirm that WGL has the operational and financial ability to accelerate its existing pipe replacement program, and we authorize the Company to do so. But the mere fact that the Company plans increased infrastructure investments does not justify a surcharge, which would represent a fundamental shift from long-standing rate-making principles. To the contrary, the record in this case demonstrates that the Company can invest significant amounts in infrastructure and can readily recover those costs in rates with an appropriate return. . . . We recognize that accelerating its pipe replacement program may require the Company to file somewhat more frequent rate cases than it would prefer. That is not, in our view, a negative outcome—rate cases afford all parties, and this Commission, the opportunity to ensure that rates are just and reasonable, and we understand that accelerated infrastructure investment may require more frequent adjustments. But ratepayers and the Company are better served if base rates are adjusted more frequently in smaller increments, and waiting longer between rate cases could lead to other undesirable results, including greater mismatches between costs and rates.

CONCLUSION

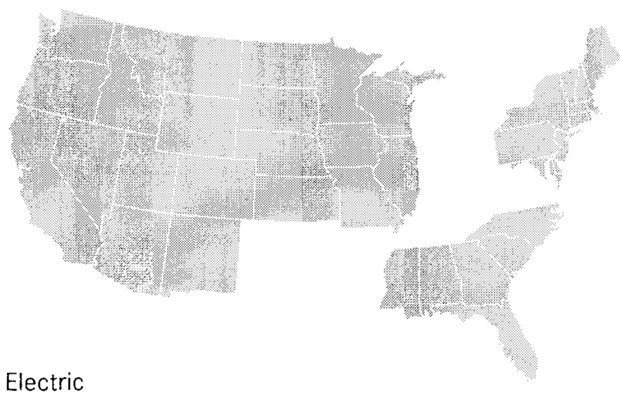
In the past, surcharges were only permitted in limited circumstances for costs that were substantial, volatile and uncontrollable, and that could harm the utilities' financial health. Examples of such traditional surcharges include fuel and purchased power adjustment mechanisms for electric utilities and gas cost recovery mechanisms for natural gas distribution utilities. In recent years, however, requests for surcharges and tracking mechanisms by utilities have significantly increased, for many different types of costs, including capital investments, for specific operating and maintenance expenses and even for revenue losses. In some instances, the use of special ratemaking mechanisms such as surcharges and other tracking mechanisms have proliferated to the point of becoming excessive and burdensome for regulators to monitor. The use of surcharges is a deviation from traditional ratemaking and puts customers at risk for overpaying for safe and reliable utility service. The use of numerous alternative ratemaking mechanisms and surcharges can defeat some of the primary principles of the rate-setting and regulatory review process. Surcharges can also result in undesirable consequences, such as reducing utility incentives to control costs, and shifting utility business risks away from investors and onto customers.

COMPARISON OF SURCHARGES USED BY COMPANIES WITH MULTI-STATE UTILITY OPERATIONS

Many of the larger utility companies serve customers in multiple states. The following section illustrates the surcharges assessed by these companies to residential customers in the states in which the utility provides service. As can be seen from the tables, the use of surcharges for most utilities varies among the states it serves. Some companies have similar surcharges for the states they serve, while the use of surcharges varies among jurisdictions for others. Whether specific surcharges are approved by regulators appears to be based on the regulatory regime in the state, not whether the company has similar existing surcharges in other states.[26] The following sections contain maps illustrating the states in which the utility serves customers.[27]

AMERICAN ELECTRIC POWER (ELECTRIC)

American Electric Power ("AEP") Company is headquartered in Columbus, Ohio. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. AEP has approximately 5.3 million retail customers. AEP serves customers in the following states:



Electric

The public utility subsidiaries and jurisdictions of AEP Company include:
- Appalachian Power Company
- Columbus Southern Power Company
- Indiana Michigan Power Company
- Ohio Power Company
- Public Service Company of Oklahoma
- Southwestern Electric Power Company

Exhibit 3 is a comparison of costs recovered through surcharges in AEP's jurisdictions:

EXHIBIT 3

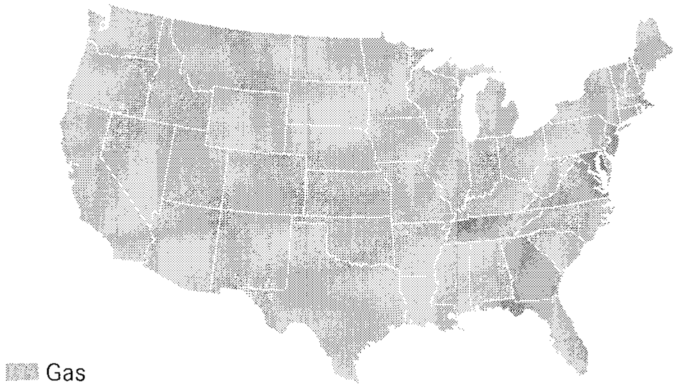
DESCRIPTION	AR	IN	KY	LA	MI	OH	OK	TN	TX	VA	WV
Advanced Metering (Voluntary)									●		
Alternative Generation	●										
Capital Expenditures											●
Capacity Charge			●								
Clean Coal Technology		●									
Energy Efficiency/DSM	●	●	●		●	●	●		●		●
Environmental Investment/ Compliance		●	●		●	●		●	●	●	
Federal Litigation Consulting Fees	●					●					
Franchise/Municipal Taxes	●		●	●	●					●	●
Inspection Fee								●			
Off System Sales		●									
PJM Cost		●									
Rate Case Expense									●[1]		
Reliability Expenditures/ Vegetation Management	●					●	●	●	●		
Sales & Use Tax			●					●		●	
Smart Grid						●					
Storm Expenses							●				
System Benefits/Universal Service									●		
Transmission Cost Recovery						●			●	●	
True-Up Case Expense									●		

[1] Two rate case expense surcharges

Source: 2010 Form 10-K and tariffs

AGL RESOURCES (GAS)

AGL is headquartered in Atlanta.[28] AGL Resources is an energy services company whose principal business is the distribution of natural gas in six states. AGL's six utilities serve approximately 2.3 million end-use customers.[29] AGL serves customers in the following states:



The public utility subsidiaries of AGL Resources include:

- Atlanta Gas Light
- Chattanooga Gas
- Elizabethtown Gas
- Elkton Gas
- Virginia Natural Gas
- Florida City Gas

Exhibit 4 is a comparison of revenues and costs recovered through surcharges in AGL's jurisdictions.

EXHIBIT 4

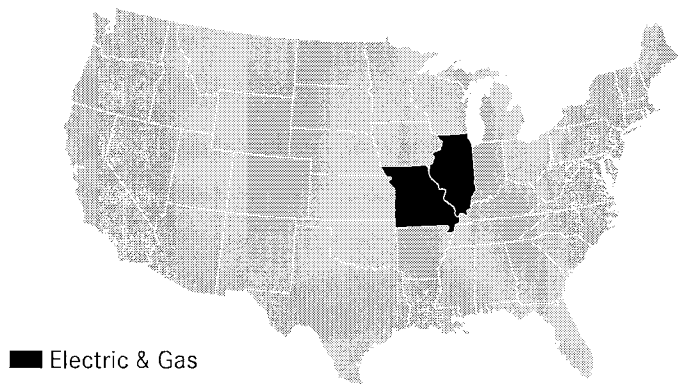
DESCRIPTION	FL	GA	MD	NJ	TN	VA
Conservation	●					
Environmental/Green House Gas Initiative		●		●		
Franchise Fees		●		●	●	
Pipeline Replacement/Utility Infrastructure Enhancement		●		●		
Revenue Normalization			●		●	●
Social Responsibility/Societal Benefits		●		●[1]		
Transitional Energy Facility Adj.				●		
Weather Normalization				●	●	●

[1] In NJ, Societal Benefits includes costs for clean energy program, environmental remediation and universal service

Source: 2010 Form 10-K and tariffs

AMEREN CORPORATION (ELECTRIC & GAS)

Ameren is a public utility holding company headquartered in St. Louis, Missouri. Ameren's subsidiaries operate rate-regulated electric generation, transmission, and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and merchant generation businesses.[30] Ameren has approximately 2.4 million electric customers and 900,000 natural gas customers.[31] Ameren serves customers in Missouri and Illinois.



The public utility subsidiaries of Ameren include:

- Union Electric Company (electric & gas)
- Ameren Illinois (electric & gas)

Exhibit 5 is a comparison of costs recovered through surcharges in Ameren's jurisdictions.

EXHIBIT 5

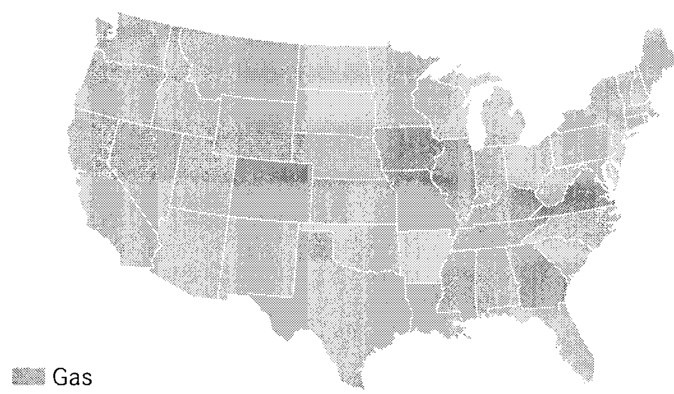
	ILLINOIS		MISSOURI	
DESCRIPTION	Electric	Gas	Electric	Gas
Coal Tar Cleanup[1]		●		
Energy Efficiency Costs	●	●		
Environmental Costs	●	●		
Excess Franchise Fees	●	●		
Government Compliance Costs	●	●		
Hazardous Materials (Asbestos)	●			
Infrastructure Maintenance	●			
Infrastructure Replacement				●
Uncollectibles	●	●		

[1]Zone 3 customers only

Source: 2010 Form 10-K and tariffs

ATMOS ENERGY CORPORATION (GAS)

Atmos Energy Corporation, headquartered in Dallas, Texas, is engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as other non-regulated natural gas businesses. The Company's primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. It also has more limited service areas in Georgia, Illinois, Iowa, Missouri and Virginia. In addition, Atmos transports natural gas for others through its distribution system. Atmos has approximately three million residential, commercial, public authority and industrial customers in 12 states located primarily in the South. Atmos serves customers in the following states:



Atmos' natural gas distribution segments include:

- Mid-Tex Division
- Kentucky/Mid-States Division
- Louisiana Division
- West Texas Division
- Colorado-Kansas Division
- Mississippi Division

Exhibit 6 is a comparison of costs recovered through surcharges in Atmos' jurisdictions:

EXHIBIT 6

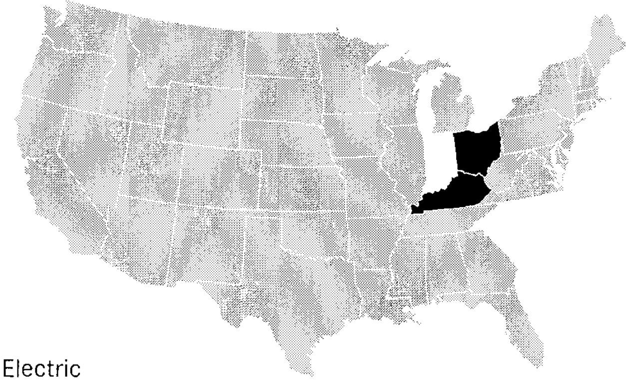
DESCRIPTION	CO	GA	IA	IL	KS	KY	LA	MO	MS	TN	MID TX	WEST TX	VA
Ad Valorem					●								
Automated Metering Incentive	●												
Demand Side Management	●					●							
Energy Efficiency			●								●	●	
Environmental										●			
Franchise Fee	●	●											
Low Income				●									
Municipal Fee											●		
Performance Based Rate Mechanism (experimental)						●							
Pipe Replacement		●				●							
Rate Case Expense											●		
Rate Stabilization/ Rate Review[1]							●		●			●	
Renewable Energy				●									
Research & Development[2]						●							
System Reliability					●								
Taxes				●							●		
Transportation Service Cost	●												
Uncollectibles			●										
Weather Normalization		●			●	●	●		●	●	●	●	●

[1]Atmos' Louisiana and Mississippi jurisdictional base rates are based on Formula Rates, which are adjusted annually, as opposed to a rate case.
[2]Voluntary participation by the Company in R&D funding for Gas Technology Institute or other research facilities.
Source: 2010 Form 10-K and tariffs

DUKE ENERGY (ELECTRIC AND GAS)

Duke Energy Corporation is an energy company that operates in the United States primarily through its direct and indirect wholly-owned subsidiaries. The Company is headquartered in North Carolina. Duke Energy supplies and delivers energy to approximately 4 million customers in the U.S.

Duke serves customers in the following states:



Duke has created a "virtual power plant" model, which combines cost recovery, lost revenue recovery and incentives into an avoided cost charge, which has been approved in the Carolinas and Ohio. Duke has proposed similar mechanisms in Indiana.

Electric
Electric & gas

The public utility subsidiaries of Duke Energy currently include:

- Duke Energy Carolinas (electric)
- Duke Energy Indiana (electric)
- Duke Energy Ohio (electric and gas)

On January 8, 2011, Duke Energy Corporation ("Duke Energy") entered into a Merger Agreement and Plan of Merger between and among Diamond Acquisition Corporation, a North Carolina corporation and Duke Energy's wholly-owned subsidiary (Merger Sub) and Progress Energy, Inc., a North Carolina corporation.[32] Progress Energy includes two major electric utilities that serve about 3.1 million customers in the Carolinas and Florida.[33] The merger is still pending.

Exhibit 7 is a comparison of costs recovered through surcharges in Duke's jurisdictions:

EXHIBIT 7

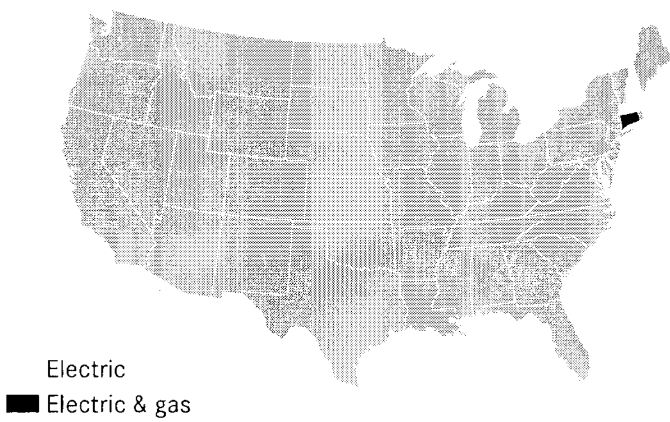
	KY		IN	NC	OH		SC
DESCRIPTION	ELEC	GAS	ELEC	ELEC	ELEC	GAS	ELEC
Accelerated Main Replacement						●	
Annually Adjusted Component					●		
Clean Coal Operating Cost Revenue Adjustment			●				
Demand Side Management	●	●	●	●			
Economic Competitiveness					●		
Emmission Allowances			●				
Energy Efficiency				●	●		●
Excise Tax					●	●	
Franchise Fee	●	●					
Infrastructure Modernization					●		
New Generation			●				
Non-fuel purchased power				●			
Off-system Power sales & Emission Allowance Sales Profit Sharing	●						
Pension Costs							●
Pollution Control			●				
Regulatory Transition Charge					●		
Reliability Adj (Capacity)			●				
Renewable Energy				●	●		
State Tax					●		
Storm Recovery					●		
System Reliability Tracker					●		
Transmission Cost					●		
Uncollectible					●	●	
Universal Service					●		

Source: 2010 Form 10-K and tariffs

NORTHEAST UTILITIES (ELECTRIC AND GAS)

Northeast Utilities ("NU") is a public utility holding company headquartered in Connecticut. The Company is engaged primarily in the energy delivery business through its wholly-owned utility subsidiaries.

NU serves customers in Connecticut, Massachusetts and New Hampshire.



The public utility subsidiaries of NU include:
- Connecticut Light & Power
- Public Service Company of New Hampshire
- Western Massachusetts
- Yankee Gas

On October 18, 2010, NU and NSTAR announced a Merger Agreement to combine the two companies. The post-transaction company will provide electric and natural gas energy delivery service to nearly 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire, representing over half of all the customers in New England. The merger is still pending.

Exhibit 8 is a comparison of costs and revenues recovered through surcharges in NU's jurisdictions:

EXHIBIT 8

	CT		NH	MA
DESCRIPTION	ELEC	GAS	ELEC	ELEC
Competitive Transition Assessment[1]	•		•	•
Decoupling				•
Electricity Consumption Tax			•	
Energy Efficiency Programs				•[2]
Exogenous Costs				•
FERC Congestion Charge	•			
Low Income				•
Pension/PBOP				•
Renewable Energy				•
Storm Recovery Costs				•
System Benefit			•	

[1] Stranded investment, conservation load management, renewable energy
[2] Two separate charges for energy efficiency & DSM
Source: 2010 Form 10-K and tariffs

MIDAMERICAN ENERGY HOLDINGS COMPANY (ELECTRIC AND GAS)

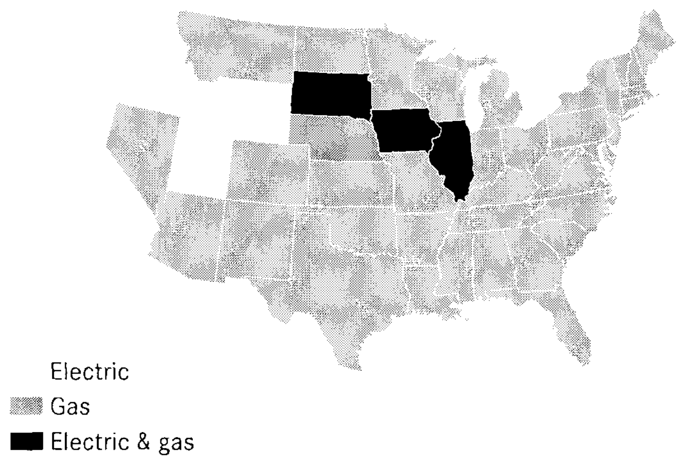
MidAmerican Energy Holdings Company ("MEHC") is a holding company that owns subsidiaries principally engaged in energy businesses (collectively with its subsidiaries, the "Company"). MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

The Company's operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, LLC, Northern Natural Gas Company, Kern River Gas Transmission Company, CE ElectricUKFunding Company, CalEnergy Philippines, CalEnergy U.S. and HomeServices of America, Inc. Through these platforms, the Company owns and operates an electric utility company in the Western United States, an electric and natural gas utility company in the Midwestern United States, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of independent power projects and the second largest residential real estate brokerage firm in the United States.

As of December 31, 2010, MEHC's electric and natural gas utility subsidiaries served 6.2 million electricity customers and end-users and 0.7 million natural gas customers. MEHC's natural gas pipeline subsidiaries operate interstate natural gas transmission systems that transported approximately 8% of the total natural gas consumed in the United States during 2010.

PacifiCorp, an indirect wholly owned subsidiary of MEHC, is a United States regulated electric utility company headquartered in Oregon that serves 1.7 million retail electric customers. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity.

MEHC serves customers in:



The public utility subsidiaries of MEHC include:
- PacifiCorp
- Pacific Power (electric)
- Rocky Mountain Power (electric)
- MidAmerican Energy (electric & gas)
- Northern Natural Gas (gas-regulated by FERC)

Exhibit 9 is a comparison of costs recovered through surcharges in MEHC's jurisdictions:

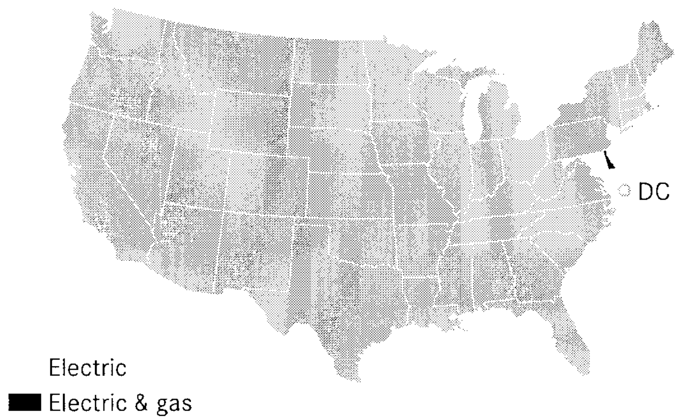
EXHIBIT 9

	CA	IA		ID	IL		NE	OR	SD		UT	WA	WY
DESCRIPTION	Elec	Elec	Gas	Elec	Elec	Gas	Gas	Elec	Elec	Gas	Elec	Elec	Elec
Alternate Energy Producer Cost Recovery		●											
Btu Adjustment			●				●			●			
Capital Investments		●											
Carbon Reduction Costs			●									●	
CARE Program	●												
Catastrophic Event Memo Account	●												
Commission Fees/ Government Fees	●	●											
Energy Efficiency/DSM [2,3]	●	●	●		●	●		●	●	●	●	●	●
Franchise Fees						●						●	
GridWest Regulatory Asset								●					
Hydro Cost Deferral												●	
Independent Evaluator Cost								●					
Intervenor Funding								●					
Klamath Dam Removal								●					
Klamath Rate Reconciliation Adjustment								●					
Low Income	●					●		●			●	●	
Nuclear Decommissioning					●								
Property Sales								●					
Public Purpose Charge								●					
Rate Mitigation Adjustment			●					●					
Renewable Energy/Solar Energy Programs/Research[1]	●	●			●	●		●			●	●	
Severance-Regulatory Asset								●					
Taxes		●	●		●	●	●	●	●	●		●	
Transition Balancing Account (includes franchise fees & uncollectibles)	●											●	●

[1]Voluntary in IA, IL and UT
[2]DSM charge in SD does not apply to all customers
[3]DSM suspended in Wyoming
Source: 2010 Form 10-K and tariffs

PEPCO HOLDINGS, INC. (ELECTRIC AND GAS)

Pepco Holdings Inc. ("PHI") is a diversified energy company that through its operating companies is engaged primarily in two businesses: the distribution, transmission and default supply of electricity and the delivery and supply of natural gas (power delivery), conducted through its regulated public utility companies. PHI has approximately 1.9 million customers in the following jurisdictions: Delaware, Maryland, New Jersey, and the District of Columbia.



The public utility subsidiaries of PHI include:

- Potomac Electric Power Company (electric)
- Atlantic City Electric (electric)
- Delmarva Power & Light (electric & gas)

Exhibit 10 is a comparison of revenues and costs recovered via surcharges in PHI's jurisdictions:

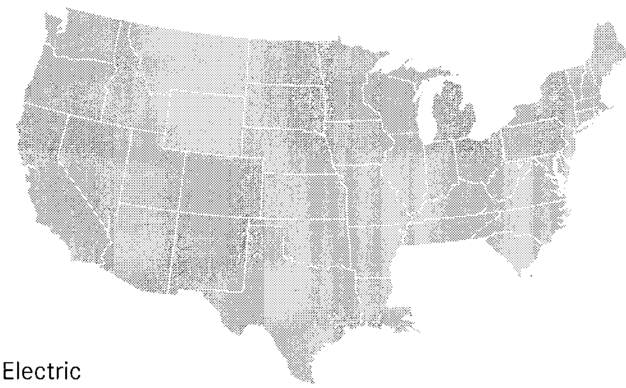
EXHIBIT 10

	DC	DE		MD	NJ
DESCRIPTION	ELEC	ELEC	GAS	ELEC	ELEC
Bill Stabilization	●			●	
Corporate Business Tax					●
Delivery Tax	●				
Demand Side Management				●	
Energy Assistance Fund[3]	●				
Environmental Expenses			●		●
Infrastructure Investment					●
Public Space Occupancy Fees	●				
Regulatory Assets Recovery[1]					●
Sales and Use Tax					●
Securitization of Stranded Costs					●
Societal Benefits[3]	●				●
Sustainable Energy Fund	●				
Transitional Facility Assessment					●
Universal Service Costs	●			●	

[1]Asbestos removal, FAS 106 Costs and other regulatory assets
[2]A new Reliability Investment Recovery Mechanism (RIM) surcharge is currently being proposed in all of PHI's regulated electric utility operating jurisdictions.
[3]Customer will pay either Societal Benefits Charge or the Energy Assistance Fund Charge, not both
Source: 2010 Form 10-K and tariffs

SOUTHERN COMPANY (ELECTRIC)

Southern Company was incorporated under the laws of Delaware on November 9, 1945 and is headquartered in Atlanta. Its traditional operating companies (which are also referred to as the Southern Company System) supply electric service to approximately 4.4 million customers, in four southeastern states: [34]



Electric

The public utility subsidiaries of Southern Company include:
- Alabama Power Company
- Georgia Power Company
- Gulf Power (serves utility customers in the Florida panhandle)
- Mississippi Power

Exhibit 11 is a comparison of costs recovered via surcharges in Southern Company's jurisdictions:

EXHIBIT 11

DESCRIPTION	AL[1]	FL	GA	MS
Ad Valorem				•
Demand Side Management/ Conservation		•	•	
Environmental Compliance		•	•	•
New Plant Construction Costs	•		•	•[2]
Performance Evaluation Plan				•
Regulatory Taxes				•
System Restoration				•
Taxes (franchise, gross receipts, etc.)	•	•	•	

[1]Alabama Power's rates are adjusted annually by the Rate Stabilization and Equalization Factor (a formula rate plan) since 1982, as opposed to setting rates based on the traditional rate case process
[2]Rider CNP to recover Construction Work In Progress costs associated with the Kemper Plant, is pending in Mississippi.
Source: 2010 Form 10-K and tariffs

SOUTHWEST GAS CORPORATION (GAS)

Southwest Gas ("SWG") is engaged in the business of purchasing, distributing and transporting natural gas in portions of Arizona, Nevada, and California. SWG is the largest distributor of natural gas in Arizona and Nevada. As of December 31, 2010, SWG purchased and distributed or transported natural gas to 1,837,000 residential, commercial and industrial customers.[35]

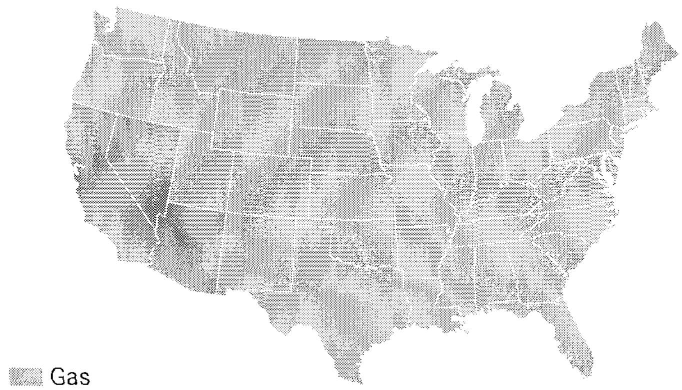


Exhibit 12 a comparison of revenues and costs recovered though surcharges in SWG's jurisdictions:

EXHIBIT 12

DESCRIPTION	AZ	CA	NV
California Alternate Rates for Energy Balancing Account		•	
Catastrophic Event Memorandum Account		•	
Customer Owned Yard Line (COYL) Cost Recovery Mechanism	•		
CPUC Reimbursement Fee		•	
Decoupling	•	•	•
Demand Side Management (DSM) Surcharge	•		
Energy Efficiency/Renewable Energy Tariff Plan	•		
Facilities Surcharge		•	
Fixed Cost Adjustment		•	
Intrastate Transportation Cost Balancing Account		•	
Low Income	•		
Low Income Energy Efficiency Balancing Account		•	
Public Interest R&D Balancing Account		•	
Research and Development Surcharge	•		
Taxes (not included in rates)			•
Transportation Franchise Fee		•	
TRIMP Surcharge	•		
Uncollectibles			•

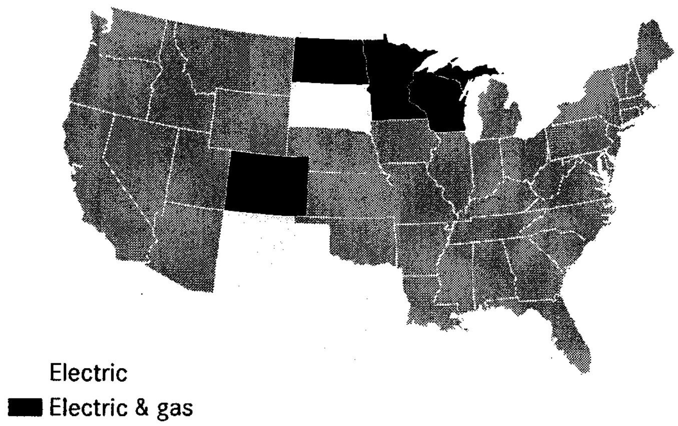
Source: 2010 Form 10-K and tariffs. In SWG's most recent rate case, Docket No. G-01551A-10-0458 before the Arizona Corporation Commission, a full revenue decoupling mechanism alternative was adopted from a settlement agreement that had been reached by most of the parties to the rate case.

Some consumer safeguards adopted in Docket No. G-01551A-10-0458 require SWG to:

- Starting April 30, 2012, file quarterly reports regarding the decoupling mechanism's performance.
- Starting April 2013, file annual reports permitting the Commission and all parties the opportunity to review the decoupling mechanism's performance.
- Be subject to an annual earnings test that would prohibit SWG from recovering any decoupling deferral amounts to the extent that the deferral recovery would increase its earnings above the authorized return on common equity.
- Provide $75,000 for the hiring of an independent consultant to conduct the annual Staff review of SWG's annual filing.
- Cap at 5 percent any surcharge developed through the decoupling mechanism that would result in a non-gas revenue surcharge of greater than 5 percent, and SWG will carry the deferral account balance forward for recovery in the following and subsequent years with no carrying charge; however, there will be no cap on annual surcharge decreases.
- Not to file a general rate application prior to April 30, 2016, with a test year ending no earlier than November 30, 2015.
- Submit a proposed customer outreach/education plan to Staff for review and approval, to outline how SWG intends to explain decoupling to customers.[36]

XCEL ENERGY (ELECTRIC AND GAS)

Xcel Energy is a holding company, with subsidiaries engaged primarily in the utility business. In 2010, Xcel Energy's continuing operations included the activity of four wholly-owned utility subsidiaries that serve electric and natural gas customers in eight states. Along with WYCO, a joint venture formed with Colorado Interstate Gas Company (CIG) to develop and lease natural gas pipeline, storage, and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the continuing regulated utility operations.[37] Xcel Energy serves 1.36 million electricity customers and 1.3 million natural gas customers.[38] Xcel serves customers in the following states:



The public utility subsidiaries of Xcel include:
- Northern States Power
- Public Service Company of Colorado
- United Water
- SPS

Exhibit 13 is a comparison of costs recovered thorough surcharges in Xcel's jurisdictions:

EXHIBIT 13

	CO		MI		MN		ND		NM	SD	TX	WI	
DESCRIPTION	Elec	Gas	Elec	Gas	Elec	Gas	Elec	Gas	Elec	Elec	Elec	Elec	Gas
Conservation/Energy Efficiency Program					•	•			•				
Demand Side Management	•	•											
Energy Optimization			•	•									
Environmental Improvement					•					•			
Facilities Fees					•								
Franchise Fees	•	•			•	•					•		
General Rate Schedule Adjustment	•	•											
Interim Rate					•		•						
Low Income (Pilot)	•	•											
Mercury Emmissions Reduction					•								
Other Taxes/Fees	•	•			•	•	•	•		•			
Pipeline System Integrity Adjustment		•											
Renewable Development					•								
Renewable Energy Standard	•				•				•				
State Energy Policy					•	•							
Transmission Capital Costs	•				•					•			

Source: 2010 Form 10-K and tariffs

APPENDIX I – DESCRIPTIONS OF TYPES OF COSTS BEING ASSESSED AS SURCHARGES

The following discussion focuses on proposed surcharges which would appear as an additional charge on ratepayers' bills, above and beyond the basic service charge and charges for fuel and taxes. Below are examples of various surcharges proposed and employed by utilities and a brief description of the costs being recovered through surcharges.

LOST REVENUES

Lost revenue surcharges are an added charge to ratepayers' bills which serve to compensate the utility for loss of revenue due to various factors. Some lost revenue surcharges include:

REVENUE DECOUPLING

Revenue decoupling helps assure that the utility's actual earnings will be at the level of authorized earnings. Under some forms of full decoupling, customers' rates are automatically adjusted to insulate the utility's earnings from fluctuations in sales. The rational for this that it removes existing disincentives which make utility management reluctant to aggressively promote energy conservation. Revenue decoupling can take on different approaches, including: decoupling true up plans, lost revenue adjustment mechanisms, and fixed/variable pricing rate design, which shifts costs into the "fixed" portion of the customer's bill and out of the "variable" portion of the bill.

Straight Fixed Variable or (SFV) is a rate design where fixed costs of service would be collected through fixed charges and only variable costs of service would be collected through usage charges. This approach would require very high basic service charges.[39]

Fixed costs are the portion of utility costs that do not change with the level of energy consumption. Within each rate class that does not have a demand charge, each customer is charged the same amount for fixed costs. Variable costs are those costs that differ depending on the amount a customer consumes (e.g., the volumetric charge per kilowatt-hour). Some items that would be considered a variable charge include fuel, some maintenance, and often purchased power. By separating these two charges, a utility's ability to recover its revenue requirement is completely separated from sales volume. By ensuring the recovery of all fixed charges, the revenue level of the company under SFV remains fairly consistent, providing a high level of certainty for investors. Additionally, SFV insulates the utility company from feeling the effects of external forces such as loss of sales due to poor weather or customer investment in energy efficiency would typically have on revenues. Alternatively, the utility company's upside from increased sales is limited.

The use of SFV can reduce savings experienced by customers from energy efficiency investments as presented in the following example[40]:

Reduction of Monthly Customer Usage from 1,000 to 900 Units Energy Efficiency Investment of $200

	STANDARD TWO-PART TARIFF	SFV
	$15 Fixed Charge $0.075/kWh	$50 Fixed Charge $0.04/kWh
1,000 Units	Fixed: $15.00 Variable: $17.00 Total: $90.00	Fixed: $50.00 Variable: $40.00 Total: $90.00
900 Units	Fixed: $15.00 Variable: $67.50 Total: $82.50	Fixed: $50.00 Variable: $36.00 Total: $86.00
Savings	$7.50/month $90/year	$4/month $48/year

WEATHER NORMALIZATION ADJUSTMENT (PARTIAL FORM OF DECOUPLING)

A weather normalization adjustment ("WNA") applies a surcharge to ratepayers' bills so that the bills reflect an amount that would be billed for utility services under normal weather conditions. For example, if gas utility customers use less gas for space heating because winter is warmer than normal, their savings are limited to the avoided gas commodity charges, and the rest of their utility bill effectively reflects the higher usage that is based on "normal" weather. Similarly, if electric customers use less air conditioning during a cooler than normal summer, what would have been their savings is reduced by having to pay the utility as if the normal hot summer weather had occurred. The opposite is also true; higher utility bills from extreme weather can be somewhat mitigated by a WNA surcredit. Weather normalization is a regulatory procedure that removes weather-related volatility from customer bills; that is, adjusts the non-gas (or distribution) charges on customers' bills to reflect normal weather instead of actual weather which may be colder or warmer than normal.[41]

EARNINGS SHARING MECHANISM/RATE OF RETURN TRACKER

An earnings sharing mechanism is a single adjustment based on the utility's rate of return. Adjustments are made outside of rate cases when actual costs deviate from test year costs and/or actual revenues deviate from test year revenues, in a manner that affects utility earnings.[42] Some earnings sharing mechanisms are based upon whether the utility earns within a band around its authorized rate of return. As an illustrative example, if a utility's authorized return on equity was 10%, an earnings sharing mechanism could have a "band" of 50 basis points (plus or minus) around that authorized ROE, earnings above a 10.5% ROE are "shared" with ratepayers via the earnings sharing mechanism as a credit, while earnings below 9.5% would result in a surcharge.

TRANSITION ADJUSTMENT

A transition or stranded cost surcharge recovers revenues lost to utilities when customers purchase their energy supply through independent marketers. The rationale for this type of surcharge is that the migration to another supplier creates "stranded costs" for the utility.

CAPITAL EXPENDITURES

GAS PIPELINE/AGING INFRASTRUCTURE REPLACEMENT

Infrastructure surcharges provide for utility recovery of capital investments made to upgrade a utility's aging electric distribution infrastructure or gas distribution pipeline system.

ATLANTA GAS LIGHT

In 1998, AGL was permitted to implement a surcharge to recover prudently incurred costs associated with a ten-year pipe replacement program ("PRP") to address specific pipeline safety violations. The PRP was scheduled to be completed but was extended to 2013 as part of a settlement in Docket No. 85616-U. The residential surcharge was $1.29 per month in years 7-9 of the PRP and increased to $1.95 in years 10-13. In 2009, the Company filed a request to rename the existing surcharge to the Strategic Infrastructure Development and Enhancement ("STRIDE") Program surcharge so that it would include the PRP costs as well as the Integrated System reinforcement Program ("i-SRP") costs and costs for expanding the distribution system. The Commission approved the Company's request for the STRIDE surcharge in its final decision dated in Docket No. 29950, dated January 20, 2010.

In contrast, Washington Gas Light ("WGL") recently sought, as part of its rate base increase, approval of an Accelerated Pipe Replacement Plan ("APRP") and a related cost recovery mechanism ("Rider") to accelerate the replacement of aging pipes, increase safety and reliability and provide environmental benefits through the reduction of greenhouse gas emissions. The APRP was approved by the regulators but the surcharge was denied by regulators because it departed from traditional ratemaking. In its order, the Maryland PSC stated it would rather review these costs in the context of a rate case, even if the filing of rate cases would be more frequent.

NEW GENERATION PLANT INVESTMENT (COAL FIRED, SOLAR, RENEWABLE, NUCLEAR GENERATION)

Some utilities have been authorized surcharges to recover investments made for the purposes of adding generation or capacity to serve more customers or meet increased demand, or for the investments in specific types of generation such as renewables or solar. For example, Progress Energy Florida ("PEF") obtained regulators' approval this year to recover $86 million from ratepayers for the costs of constructing nuclear Units Levy 1 and 2. The estimated 2012 monthly cost to ratepayers is about $2.93 for the first 1,000 kilowatt hours (kwh) for PEF customers.

Florida Power & Light Company ("FP&L") also received regulators' approval to recover $196 million for costs associated with construction of two new units at its Turkey Point Plant and adding capacity to existing units at Turkey Point and St. Lucie Plants.[43]

SMART METERS/SMART GRID

"Smart Meters"[44] and "Smart Grid" generally refer to technology to convert and automate utility electricity delivery systems, and enable new functions, such as grid monitoring and time-of-use metering. Many utilities are proposing to rapidly implement these technologies, but some utilities and regulators have found that the costs are much higher than anticipated and/or ratepayer benefits were not commensurate. There have been requests by electric utilities for surcharge recovery of costs for Advanced metering Infrastructure ("AMI"). In 2010, regulators in Texas allowed Oncor Utilities to implement a monthly surcharge of $2.19 per customer for 11 years to pay for the costs associated with installing smart meter as well as a public education campaign.[45]

The New York PSC authorized Con Edison to recover Smart Grid costs through a surcharge. While the monthly surcharge averages about 28¢/customer, or less than 0.3% of the average monthly bill, the surcharge will collect over $145 million for the company. The surcharge continues at least until Con Edison's next rate case, in April 2013, when it may be reset.[46]

However, other states have disallowed surcharges to recover these substantial and speculative costs:

MARYLAND

Baltimore Gas & Electric Proposed a SmartGrid Plan in Case No. 9208, Order 83410, and requested that the $835 million cost to implement be recovered from customers via a surcharge. The Commission denied the company's Smart Grid Plan and surcharge recovery. The Commission's decision stated:

> The Proposal asks BGE's ratepayers to take significant financial and technological risks and adapt to categorical changes in rate design, all in exchange for savings that are largely indirect, highly contingent and a long way off. We are not persuaded that this bargain is cost-effective or serves the public interest, at least in its current form.
>
> ...
>
> The Proposal is a 'no-lose proposition' for the Company and its investors.[47]

BGE submitted a modified SmartGrid plan in Case No. 9208. The Commission approved BGE's modified SmartGrid plan, but again did not permit recovery of the project through a surcharge. The Commission supported intervenor, the Maryland Energy Administration's (MEA), position that AMI deployment is analogous to an investment in a power plant, an investment of similar (or greater) magnitude that historically would be recovered through traditional ratemaking.[48]

RENEWABLE ENERGY

Renewable energy surcharges recover costs related to capital expenditures or purchased power contracts associated with a utility's renewable energy program. Renewable energy is defined as energy that can be replenished, such as wind, solar, geothermal, hydro, photovoltaic, wood and waste. Renewable energy typically also has environmental benefits. To encourage the development of renewable energy, many jurisdictions provide for utility cost recovery via surcharges. Non-renewable energy sources are finite, such as coal, oil, and gas.[49]

TRANSMISSION INFRASTRUCTURE

Transmission surcharges can include provisions for utility recovery of capital expenditures to upgrade a utility's aging transmission infrastructure and/or transmission cost increases which the utility incurs based on transmission costs approved by the FERC. Some state regulatory commission prefer to isolate the impacts on utility customer bills resulting from federal mandates, including FERC decisions, so those impacts are transparent to customers and are distinguished from state regulatory decision impacts.

OPERATION AND MAINTENANCE EXPENSES

PIPELINE SAFETY PROGRAM FEES

Utilities have proposed surcharges to recover costs associated with inspecting gas distribution pipelines and safety related issues.

VEGETATION MANAGEMENT

Vegetation management activities can include: tree pruning (trimming), right-of-way mowing and clearing, and herbicide application.[50] A major cause of power outages can be due to improperly maintained vegetation or trees that can come in contact with power lines during severe storms.

ENVIRONMENTAL COMPLIANCE

Environmental compliance costs can include remediation costs associated with site investigation and removal of pollution or contaminants from soil or groundwater[51] or costs to implement environmental controls mandated by state and federal regulations.[52] A common example of environmental compliance costs is the emission control equipment that electric generation utilities are required to install on coal-fired plants to meet air quality standards.

UNCOLLECTIBLE CHARGES

Some utilities have requested surcharges to collect customers' bad debts. Some surcharges allow a utility to collect from (or refund) the difference between the uncollectible (or bad debt) expense allowed in base rates and the utility's actual prior calendar year uncollectible expense. Some utility uncollectible surcharges recover only the fuel or gas cost portion of uncollectible accounts.[53] In some cases, the uncollectible expense may be collected though the utility's fuel or gas clause.

PENSION/OTHER POST RETIREMENT BENEFITS ("OPEB")

Prior to 2008, many utilities' defined benefit pension plans were well funded. However, due to the sharp decline of the stock market in late 2008 with the onset of the world-wide financial crisis, many utilities' pension plans suffered substantial losses. In the following years, some utilities requested substantial increases to their pension expense to replenish the funding of their pension plans, some via a surcharge. The stock market has since stabilized.

STORM DAMAGE

A catastrophic storm may cause significant damage to a utility's infrastructure (wires, poles, substations, etc.). Some utilities have petitioned regulators to recover the costs associated with repairing its infrastructure via a surcharge mechanism. Traditionally, utility storm damage repair costs have been addressed in base rates.

ENERGY EFFICIENCY/CONSERVATION/DEMAND SIDE MANAGEMENT (DSM) PROGRAMS

Costs associated with implementing energy efficiency, conservation and demand side management programs are increasingly being addressed for ratemaking purposes in utility surcharge mechanisms.

UNIVERSAL SERVICE COSTS (LOW INCOME PROGRAM COSTS)

A universal service cost is a fee paid by users of a utility service in some states to support the provision of providing utility service for low-income users. The fees help eligible customers pay their electricity bills and may also provide for energy conservation measures and weatherization.[54]

MUNICIPAL FEES/FRANCHISE FEES

Some utilities pass through fees imposed on the utility by the municipality for franchise, occupation taxes/fees, or any other tax/fee imposed on the company by the municipality to conduct business within the city limits and on the cities' rights-of-way to its customers.[55] Typically, special surcharges for municipal fees or taxes would be applicable to utility customers residing within the municipality that is imposing such surcharges on the utility.

AD VALOREM TAXES

Ad Valorem taxes are taxes based on assessed value of property (i.e., property taxes).

OTHER TAXES

Some utilities impose a surcharge to collect other taxes such as sales and use tax, gross receipts tax, etc.

STRANDED COSTS

Costs incurred by utilities to serve their customers that potentially may be unrecoverable in a newly-created market.[56] Stranded costs can be defined as the estimated decline in the value of electricity-generating assets due to restructuring of the industry.[57]

SOCIETAL BENEFITS CHARGE OR SYSTEM BENEFITS CHARGE

In some jurisdictions, such as New Jersey and Arizona, utilities collect from customers a "societal benefits charge" which allows the utility to recover a combination of costs: e.g., clean energy program costs, manufactured gas plant remediation expenses, universal service fund and other allowed costs.[58]

REGULATORY FEES

These fees can include rate case costs, regulator fees, etc.

LITIGATION COSTS

Legal fees and costs associated with a trial, if significant or unusual, would be the subject of a special surcharge request by a utility. Traditionally, utility legal costs are addressed in the determination of the utilities' base rates.

CAPITAL/O&M COMBINED

ECONOMIC STIMULUS PROGRAM ("ESP")

In some jurisdictions, such as New Jersey, costs and associated carrying costs incurred on behalf of the utility for reliability focused and energy efficiency focused infrastructure projects are within the Economic Stimulus Program ("ESP"), which is a specific utility cost recovery mechanism. ESP Costs include: (1) the carrying costs (depreciation and return on net investment, including tax effects) on capital investments and (2) the incremental operation and maintenance expenses associated with the infrastructure programs.

ENVIRONMENTAL COMPLIANCE

Capital expenditures and O&M associated with installing environmentally compliant plant equipment that reduces or removes the level of harmful substances being emitted into the atmosphere. This can include costs for environmental remediation (i.e., clean-up).

SYSTEM HARDENING/RELIABILITY COSTS

Proactive measures to increase a utility's transmission and distribution system to withstand the effects of high winds and storms. This can also include investments to upgrade or underground the infrastructure.

SECURITY COSTS

Security costs include proactive measures to protect a utility's infrastructure from security threats. After the September 11, 2001 terrorist attacks on the World Trade Center, some utilities began requesting special cost recovery for the increased costs for security threats to water supply and treatment facilities and to other potential terrorist targets such as nuclear generating plants.

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Over the past 31 years, Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors, including AARP, on several occasions.

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END NOTES

[1] Public Utilities Commission of Minnesota, Utility Rates Study, 2010, Talking Points on Cost Trackers, The National Regulatory Research Institute Presentation, November 2009.

[2] The Two Sides of Cost Trackers: Why Regulators Must Consider Both, October 27, 2009.

[3] The International Accounting Standards Board (IASB) Framework lists prudence as a sub-quality of reliability, calling prudence "the inclusion of a degree of caution in the exercise of the judgments needed in making the estimates required under conditions of uncertainty, such that assets or income are not overstated and liabilities or expenses are not understated" (paragraph 37). Also, Financial Accounting Standards Board ("FASB") Concepts Statement 2 discusses conservatism—meaning prudence—at length in paragraphs 91–97.

[4] Used and useful is defined by the Edison Electric Institute's 2005 Glossary of Electric Terms as "A regulatory specification typically used to determine whether an item of "Plant" may be included in a utility's rate base.

[5] http://nrri2.org/index.php?option=com_content&task=view&id=97&Itemid=48. Public Utilities Commission of Minnesota, Utility Rates Study, 2010.

[6] Cost Recovery Mechanisms for Smart Grid Investment, Carl Peterson, Center for Business and Regulation, University of Illinois Springfield.

[7] Public Utilities Commission of Minnesota, Utility Rates Study, 2010.

[8] http://www.nj.gov/bpu/residential/glossary/ In states which have restructured their retail electric markets, the transmission and distribution rates remain regulated.

[9] Public Utilities Commission of Minnesota, Utility Rates Study, 2010.

[10] The Two Sides of Cost Trackers: Why Regulators Must Consider Both, October 27, 2009.

[11] The terms used may vary slightly between different jurisdictions and are not used uniformly by utility regulators.

[12] http://www.georgiapower.com/pricing/glossary.asp#rider

[13] Aquila, Order in Application No. NG-0041

[14] Balancing accounts are usually classified as "one way" (or "asymmetrical") where under-spending is returned to ratepayers, but overspending is absorbed by company. Under a two-way ("or symmetrical") balancing account, the impact of underspending and overspending, if deemed to be prudent, is ultimately passed on to the ratepayer.

[15] A balancing account may be recorded as a regulatory asset or a deferred asset on the utility's books. Qualifying costs are charged to the balancing account and the surcharge revenues collected are credited to the account. Balances in some balancing accounts earn the 90-day commercial payment rate.

[16] Memorandum ("memo") accounts are used extensively by California utilities, with more limited or no use in other jurisdictions. The costs being tracked may later be converted to a balancing account upon approval by the regulator. In California, information regarding memorandum accounts are reported by filing "Advice Letters".

[17] A.10-07-007

[18] This information was obtained from the tariffs on the utilities' websites during the timeframe of this report.

[19] Utah Code Annotated Section 54-7-13(4)

[20] Direct Testimony of Greg Shimansky, GDS-1, A. 10-12-005

[21] Direct Testimony of Jodi Jerich, on behalf of RUCO, Docket No. G-04204A-11-0158

[22] Testimony of David Dismukes, Docket No. 09-00183, Testimony of Jodi Jerich, G-04204A-11-0158

[23] http://coa.courts.mi.gov/documents/OPINIONS/FINAL/COA/20120410_C296374_47_296374.OPN.PDF

[24] *Id.*, at 8

[25] *Id.*, at 8

[26] The array of surcharges being proposed and implemented by utilities is continuously evolving. Information for the utilities listed is believed to be accurate at the time the research was conducted, but is subject to change as new regulatory developments occur.

[27] It should be noted that the utility may only serve customers in a portion of the states shown.

[28] http://www.aglresources.com/about/about_us.aspx

[29] AGL Resources 2010 Form 10-K p. 4

[30] 2010 Form 10-K

[31] http://www.ameren.com/aboutameren/pages/aboutus.aspx

[32] 2010 Form 10-K

[33] https://www.progress-energy.com/company/about-us/index.page?

[34] http://www.southerncompany.com/aboutus/home.aspx

[35] Southwest Gas Corporation, Form 10-K, 2010

[36] Proposed Decision dated November 28, 2011

[37] 2010 Form 10-K

[38] http://www.metrodenver.org/investor-center/2011/xcel-energy.html

[39] Direct Testimony of Leland Snook on behalf of APS, Docket No. E-01345A-11-0224

[40] Source: https://aep.com/about/IssuesAndPositions/Financial/Regulatory/AlternativeRegulation/StraightFixedVariable.aspx

[41] Ralph Miller Direct Testimony, Brooks Congdon, on behalf of Southwest Gas Corp., Docket No. G-01551A-07-0504

[42] Utility Rates Study, July 22, 2010 by the Minnesota Public Utilities Commission to the Senate Energy, Utilities, Technology & Communications Committee.

[43] http://citrusdaily.com/psc-approves-nuclear-cost-recovery-progress-energy-fpl/2011/10/25/87681.html

[44] Also referred to as "Advanced Meters".

[45] http://www.greentechmedia.com/articles/read/smart-grid-cost-recovery-make-the-consumer-care/

[46] www.smartgridtoday.com/public/2174print.cfm, Order in Case 09-E-0310, http://www.coned.com/documents/elec/159-164a.pdf

[47] MD PSC Order No. 83410, pp. 1,3, dated June 21, 2010.

[48] MD PSC Order No. 83531, pp. 32-41.

[49] 2005 EEI Glossary.

[50] http://www.oncor.com/community/vegetation/default.aspx

[51] http://en.wikipedia.org/wiki/Environmental_remediation

[52] http://www.georgiapower.com/pricing/glossary.asp#r1

[53] Atmos Energy

[54] http://www.nj.gov/bpu/residential/glossary/

[55] http://www.georgiapower.com/pricing/glossary.asp#r2

[56] 2005 EEI Glossary

[57] http://www.cbo.gov/doc.cfm?index=976&type=0

[58] South Jersey Gas

AARP
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ARIZONA WATER COMPANY

DOCKET NO. W-01445A-12-0348

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON

COST OF CAPITAL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MARCH 1, 2013

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EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's ("RUCO") analysis of Arizona Water Company's application for a permanent rate increase for its Northern Group, filed with the Arizona Corporation Commission ("ACC" or "Commission") on August 1, 2012, RUCO recommends the following:

Cost of Common Equity – RUCO recommends that the Commission adopt an 8.75 percent cost of common equity. This 8.75 percent figure is the high side of the range of results obtained in RUCO's cost of equity analysis, and is 255 basis points lower than the 11.30 percent cost of equity capital proposed by Arizona Water Company in its application for a permanent rate increase.

Cost of Debt – RUCO recommends that the Commission adopt Arizona Water Company's proposed 6.82 percent cost of Long-term debt.

Capital Structure – RUCO recommends that the Commission adopt Arizona Water Company's proposed capital structure comprised of 51.05 percent common equity and 48.95 percent long-term debt.

Weighted Average Cost of Capital – RUCO recommends that the Commission adopt RUCO's recommended 7.81 percent weighted average cost of capital ("WACC") which is the weighted cost of RUCO's recommended costs of common equity and long-term debt, and is 130 basis points lower than the 9.11 percent WACC being proposed by Arizona Water Company.

RUCO disagrees with a number of inputs that Arizona Water Company's cost of capital consultant relied on in both the discounted cash flow ("DCF") model and the capital asset pricing model ("CAPM") which were used to develop a proposed cost of common equity estimate of 11.30 percent. This includes her reliance on earnings per share forecasts as opposed to also taking estimates of future growth in dividends and book value per share into consideration for the growth component of the DCF model; her use of forecasted long-term treasury instruments as the input for the risk-free rate of return component in the CAPM model; and the unreasonably high market risk premium the she uses in the CAPM model. Finally, RUCO disagrees with the 0.50 percent credit risk adjustment and the 0.45 percent business risk adjustment that is part of Arizona Water Company's proposed 11.30 percent cost of equity capital.

INTRODUCTION

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

A. My Name is William A. Rigsby. I am the Chief of Accounting and Rates for 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 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 "Company") application for a permanent rate increase ("Application") for the Company's Northern Group water systems that was filed with the Arizona Corporation Commission on August 1, 2012. AWC has chosen the operating period ended December 31, 2011 for the test year ("Test Year") in this proceeding. The Company has elected not to conduct a reconstruction cost new less depreciation study ("RCND") for the purpose of establishing a fair value rate base, and to use its original cost rate base as its fair value rate base for the purpose of establishing a fair value rate of return on its invested capital.

Q. Briefly describe AWC and the Company's Northern Group.

A. AWC is a closely held public service company which is a wholly owned subsidiary of Utility Investment Company, which in turn is a wholly owned subsidiary of United Resources, Inc. AWC provides water service to a number of communities in Arizona through three separate geographical operating groups: the Northern Group, which is the subject of this proceeding, the Eastern Group and the Western Group. The Northern Group is comprised of two systems: the Verde Valley system which includes the Company's Pinewood and Rimrock operating systems and is partially consolidated with the Sedona operating system (the Company is proposing that the Sedona operating system be fully consolidated with the Verde Valley system in this proceeding); and the Navajo system which is comprised of the Company's Lakeside and Overgaard operating systems.

Q. Is this your first case involving AWC?

A. No. I have been involved with a number of AWC proceedings dating back to 2001.

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

A. I will address the cost of capital issues associated with the case.

Q. Will RUCO also offer direct testimony on the rate base, operating income and rate design issues in this proceeding?

A. Yes. The rate base and operating income issues associated with the case will be addressed by RUCO witness Jorn L. Keller. RUCO Witness Robert B. Mease will sponsor testimony on RUCO's rate design

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 cost of common equity (the Company has no preferred stock) and my recommended cost long-term debt. The recommendations contained in this testimony are based on information obtained from Company responses to data requests, AWC's Application, and from market-based research that I conducted during my analysis.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Exhibit 1, Attachments A through D and 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, a summary of my testimony and recommendations 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 return 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 the Company is operating. Fourth, I will discuss my recommended cost of long-term debt for AWC. The fifth section of my direct testimony is devoted to a discussion of my recommended capital structure for the Company. Sixth I will discuss my recommended weighted average cost of capital. In the Seventh and final section, I will comment on the Company's cost of capital testimony. Exhibit 1, Attachments A through D and 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, I am making the following recommendations:

<u>Cost of Common Equity</u> – I am recommending that the Commission adopt an 8.75 percent cost of common equity. This 8.75 percent figure is the high side of the range of results obtained in my cost of equity analysis, and is 255 basis points lower than the 11.30 percent cost of common equity capital proposed by AWC in its application for a permanent rate increase.

<u>Cost of Debt</u> – I am recommending that the Commission adopt the Company-proposed 6.82 percent cost of Long-term debt.

<u>Capital Structure</u> – I am recommending that the Commission adopt the Company-proposed capital structure comprised 51.05 percent common equity and 48.95 percent long-term debt.

<u>Weighted Average Cost of Capital</u> – I am recommending that the Commission adopt my recommended 7.81 percent weighted average cost of capital ("WACC") which is the weighted cost of my recommended costs of common equity and long-term debt, and is 130 basis points lower than the 9.11 percent WACC being proposed by Arizona Water Company.

Q. Why do you believe that your recommended 8.75 percent WACC is an appropriate rate of return for the Company to earn on its invested capital?

A. The 8.75 percent WACC figure that I am recommending meets the criteria established in the landmark Supreme Court cases of <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u> (262 U.S. 679, 1923) and <u>Federal Power Commission v. Hope Natural Gas Company</u> (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 8.75 percent. My recommended 8.75 percent cost of equity figure is the high side of the range of results derived from my DCF and CAPM analyses, which utilized a sample of publicly traded water providers and a sample of natural gas local distribution companies ("LDCs"). The results of my DCF and CAPM analyses are summarized on page 2 of my Schedule WAR-1.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate the Company'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 the Company's cost of equity capital.

Q. In determining the rate of future dividend growth for the Company, 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]

[1] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

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 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,

[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%

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.

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[3] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = <u>6.00%</u>

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. Can you cite a more recent case in which the Commission adopted a cost of capital estimate that included this assumption?

A. Yes. The Commission adopted a RUCO recommended cost of common equity which relied on the same assumption in a 2009 Global Water rate case proceeding.[6] Decision No. 71878, dated September 14, 2010 stated the following:

> "We find that the evidence presented by RUCO as a basis for its cost of equity recommendation constitutes substantial evidence in support of its cost of equity recommendation. We further find that the evidence presented by the Company as a basis for its cost of equity recommendation contrary to RUCO's assertion, constitutes evidence that is no less substantial in support of its recommendation and of Staff's acceptance thereof. The methodologies on which each of the parties relied in making their cost of equity recommendations are clearly set forth in the hearing exhibits. Based on a consideration of all the evidence presented in this proceeding, we find a cost of common equity of 9.0 percent to be reasonable in this case. This level of return on equity reasonably and fairly balances the needs of Applicants and their ratepayers, is reflective of current market conditions, and results in the setting of just and reasonable rates."

...

[6] Docket Number W-02445A-09-0077

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 six publicly traded water companies and a natural gas proxy group consisting of nine natural gas local distribution companies ("LDCs") that have similar operating characteristics to water providers.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of the Company?

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 in this case where shares of are closely held and not publicly-traded on a stock exchange. Because of this situation, I used the aforementioned proxy that includes four publicly-traded water companies and nine LDCs.

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 the Company?

A. The six water companies used in the proxy are publicly traded on the both the New York Stock Exchange ("NYSE") and the NASDAQ.[7] All of the 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 January 18, 2013 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. I have used five of the six water utilities in prior rate case proceedings. In this case I am including American Water Works Company, Inc., (NYSE stock ticker symbol "AWK") the largest investor-owned water and wastewater utility in the U.S. American Water Works Company, Inc. has been followed by Value Line since July of 2008 after the New Jersey-based water provider was spun off from its German parent, RWE, AG and became a publicly traded entity. Value Line now has four years of operating numbers available on American Water Works Company, Inc. and so I've decided to include it in my sample of water utilities.

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[7] "NASDAQ" originally stood for "National Association of Securities Dealers Automated Quotations". Today it is the second-largest stock exchange in the world, after the New York Stock Exchange ("NYSE").

Q. Please describe the other water utilities that comprise your water company proxy group.

A. My water company proxy group also includes American States Water Company (stock ticker symbol "AWR"), California Water Service Group ("CWT"), Middlesex Water Company (stock ticker symbol "MSEX", which is traded on the NASDAQ), SJW Corporation ("SJW"), 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 the companies in my samples by their appropriate stock ticker symbols henceforth.

Q. Briefly describe the areas served by the companies in your water company sample proxy.

A. AWK operates in over 30 U.S. states and Canada. AWR 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. As described earlier in my testimony, MSEX serves customers in New Jersey, Delaware and Pennsylvania. SJW serves approximately 226,000 customers in the San Jose area and approximately 8,700 customers in a region located between Austin and San Antonio, Texas. 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. What criteria did you use in selecting the natural gas LDCs included in your proxy for the Company?

A. As are the water companies that I just described, each of the natural gas LDCs used in the proxy are publicly traded on a major stock exchange (all nine trade on the NYSE) and are followed by Value Line. Each of the nine LDCs 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 nine natural gas LDCs 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"), 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").

Q. Are these the same LDCs that you have used in prior rate case proceedings?

A. Yes, I have used these same LDCs in prior cases including two of the most recent water company proceedings that I have testified in before the Commission.[8]

Q. Briefly describe the regions of the U.S. served by the nine natural gas LDCs that make up your sample proxy.

A. The nine LDCs listed above provide natural gas service to customers in the Middle Atlantic region (i.e. NJR 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, 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.

...

[8] Arizona Water Company Eastern Group Rate Case, Docket No. W-01445A-11-0310 and Pima Utility Company Docket Numbers W-02199A-11-0329 and SW-02199A-11-0330.

Q. Are these the same water and natural gas companies that AWC used in its application?

A. No. AWC's consultant, Pauline Ahearn relied on a sample comprised of nine water providers which also included Artesian Resources Corp., Connecticut Water Service, Inc. and York Water Company.

Q. Why didn't you include Artesian Resources Corp., Connecticut Water Service, Inc. and York Water Company in your sample of water providers?

A. Artesian Resources Corp. Is not followed by Value Line and so I wasn't able to obtain comparable information on it. In the past, both Connecticut Water Service, Inc. and York Water Company were only followed in Value Line's Small and Mid-Cap Edition which did not provide five-year projections on growth and earnings which I rely on in making my cost of common equity estimates. Connecticut Water Service, Inc. is now followed in Value Line's Large Cap Edition and, while I did not include it in the analysis presented in my direct testimony, I will include it in the analysis presented in my surrebuttal testimony.

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 2007 to 2011 for both the water companies and for the LDCs. Schedule WAR-5 also includes Value Line's projected 2012, 2013 and 2015-17 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for the both the water utilities and the LDCs in my sample.

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 WTR as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described earlier on pages 11 and 12 of my direct testimony) to multiply WTR's earned return on common equity by its earnings retention ratio for each year in the 2007 to 2011 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 2, WTR had sustainable internal growth that averaged 3.36 percent during the 2007 to 2011 observation period. The company experienced a decline in growth from 3.14 percent in 2007, to 2.69 percent in 2009. Internal growth climbed to 3.65 percent during the final year of the observation period. Value Line's analysts expect this pattern to continue for the most part in the coming years. Internal growth is expected to climb steadily to 5.09 percent by the end of 2017. After weighing Value Line's earnings and book value estimates, I believe that internal growth of 5.10 percent is reasonable for WTR. (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 number of shares outstanding for WTR increased from 133.40 million in 2007, to 138.87 million in 2011. Value Line is forecasting higher future share growth. According to Value Line's analysts, outstanding shares should increase from 140.90 million in 2012 to 143.90 million by the end of the 2015-17 time period. Based on Value Line's slightly higher expectations, I believe that a 0.75% rate of share growth is appropriate (Page 2 of Schedule WAR-4). My final dividend growth rate estimate for WTR is 5.76 percent (5.10 percent internal growth + 0.67 percent external growth) 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 4.90 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 your proxy of natural gas LDCs?

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 for my natural gas sample is 4.90 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 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 4.90 percent growth estimate falls below Zacks' average long-term EPS projection of 6.60 percent for the water companies in my sample and

Value Line's growth projection of 4.92 percent (which is an average of EPS, DPS and BVPS). My 4.90 percent estimate is 40 basis points higher than the 4.50 percent average of Value Line's historical growth results and 9 basis points lower than the 4.99 percent average of the growth data published by Value Line and Zacks. My 4.90 percent growth estimate is also 143 basis points higher than Value Line's 3.47 percent 5-year compound historical average of EPS, DPS and BVPS. On balance, I would say my 4.90 percent growth estimate, derived from Value Line data, is not out of line with the growth projections that are available to the investing public.

Q. How do your average growth rate estimates on natural gas LDCs compare to the growth rate data published by Value Line and other analysts?

A. As can be seen on Schedule WAR-6, my 4.90 percent growth estimate for the natural gas LDCs is 48 to 49 basis points higher than the average 4.42 percent average of long-term EPS consensus projection published by Zacks, and the 4.41 percent Value Line projected estimate (which is an average of EPS, DPS and BVPS). The 4.90 percent estimate that I have calculated is 25 basis points lower than the 5.15 percent average of the 5-year historic EPS, DPS and BVPS means of Value Line and is also 17 basis points higher than the combined 4.73 percent Value Line and Zacks averages displayed in Schedule WAR-6. In fact, my 4.90 percent growth estimate exceeds Value Line's 4.48 percent 5-year compound historical average of EPS, DPS and BVPS by 42 basis points. In the case of the LDCs I would say that my 4.90 percent estimate is more optimistic than the growth projections for natural gas LDCs being 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 LDCs I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's January 18, 2013 Ratings and Reports water utility industry update and Value Line's December 7, 2012 Ratings and Reports natural gas utility update. I then divided those figures by the eight-week average daily adjusted closing price per share of the appropriate utility's common stock. The eight-week observation period ran from December 3, 2012 to January 25, 2013. The average dividend yields were 3.07 percent and 3.84 percent for the water companies and natural gas LDCs, respectively.

...

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 Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 7.97 percent for the water utilities and 8.75 percent for the natural gas LDCs which is 366 to 444 basis points higher than the current 4.31 percent yield on a safer Baa/BBB-rated utility bond (Attachment D).

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[9], 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.[10] 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.

[9] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[10] 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.

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. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM is 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 (Attachment D) will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[11] 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

[11] 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.

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 testimony, this compensation translates into higher rates of returns to the investor.

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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 30-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated December 7, 2012 through January 25, 2013 (Attachment D). This resulted in a risk-free (r_f) rate of return of 2.95 percent.

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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.

Q. Why did you use the yield on a 30-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 more closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect. In prior rate cases I have relied on the yields of the 5-year Treasury instrument, however for the sake of argument in this case, I have used the higher yield of the longer term 30-year Treasury bond. As I will discuss later in my testimony, the yields of long-term U.S. Treasury instruments are currently falling as a result of recent actions being undertaken by the U.S. Federal Reserve to stimulate the U.S. economy.

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 2011 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-four year period. The market risk premium (r_m - r_f) that results by using the geometric mean of these inputs is 4.10 percent (9.80% - 5.70% = 4.10%). The market risk premium that results by using the arithmetic mean calculation is 5.70 percent (11.80% - 6.10% = 5.70%).

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 January 13, 2013 for the water companies and December 7, 2012 for the natural gas LDCs. 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 0.60 to 0.85 with an average beta of 0.69. The beta coefficients for the LDCs included in my natural gas sample ranged from 0.55 to 0.75 with an average beta of 0.66.

...

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 5.79 percent for the water companies and 5.64 percent for the natural gas LDCs. My calculation using an arithmetic mean results in an average expected return of 6.90 percent for the water companies and 6.69 percent for the natural gas LDCs.

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)	7.97%
DCF (Natural Gas Sample)	8.75%
CAPM (Water Sample)	5.79% – 6.90%
CAPM (Natural Gas)	5.64% – 6.69%

Based on these results, my best estimate of an unadjusted range for a cost of common equity for the Company is 5.64 percent to 8.75 percent. My final recommended cost of common equity figure is 8.75 percent which is the high end of the range of estimates shown above (Schedule WAR-1, Page 3) and 444 basis points higher than the current 4.31 percent yield on a safer Baa/BBB-rated utility bond. My final estimate also falls within the range of projected returns on book common equity that Value Line is projecting for both the water and natural gas utility industries (Attachment A & B).

As I will discuss in more detail in the next section of my testimony, my final estimate also takes into consideration current interest rates (as the cost of equity moves in the same direction as interest rates) and the current state of the national economy. My final estimate also takes into consideration the U.S. Federal Reserve's recent decisions not to raise interest rates as long as the level of unemployment remains above 6.50 percent and on inflation holding to within a half percentage point of the Fed's 2.00 percent target.[13] I also took into consideration information on Arizona's economy and current rate of unemployment in making my final cost of equity estimate.

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[13] U.S. Federal Reserve press release dated January 30, 2013: http://www.federalreserve.gov/newsevents/press/monetary/20130130a.htm

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.30 percent cost of equity capital reflected in the Company's Application is 255 basis points higher than the 8.75 percent 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 describe your analysis of the current economic environment.

A. My analysis begins with a review of the economic events that have occurred between 1990 and the present in order to provide a background on how we got to where we are now. It also describes how the Board of Governors of the Federal Reserve System ("Federal Reserve" or "Fed") and its Federal Open Market Committee ("FOMC") used its interest rate-setting authority to stimulate the economy by cutting interest rates during recessionary periods and by raising interest rates to control inflation during times of robust economic growth. 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, then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[14] 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

[14] 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.

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.

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. Over the next ten years, the FOMC continued to stimulate the economy and keep inflation in check by raising and lowering the federal funds rate.

Q. How did the U.S. economy fare between 2001 and 2007?

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. Disappointing economic data releases, since the beginning of 2001, preceded the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon which are now regarded as a defining point during this economic slump. From January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times in order to stimulate growth. 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 during a period in which the economic picture turned considerably brighter as both Inflation and unemployment fell, wages increased and the overall economy, despite continued problems in housing, grew briskly.[15]

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. Once again, the Fed managed to engineer a soft landing.

Q. What has been the state of the economy since 2007?

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

[15] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

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 beginning of what is now being referred to as the Great Recession; the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate unchanged at 5.25 percent.[16] 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 its open market operations) into the credit markets.[17] 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

[16] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007.

[17] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007.

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, [18] 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.

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.

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[18] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007.

Q. What actions has the Fed taken in regard to interest rates since the beginning of 2008?

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 believed would moderate during the economic slowdown).[19] As a result of the Fed's actions, the federal funds rate was reduced to a level of 2.00 percent. From April 30, 2008 through September 16, 2008, the Fed took no further action on its key interest rate. However, the days before and after the Fed's September 16, 2008 meeting saw longstanding Wall Street firms such as Lehman Brothers, Merrill Lynch and AIG failing as a result of their subprime holdings. By the end of the week, the Bush administration had announced plans to deal with the deteriorating financial condition which had now become a worldwide crisis. The administrations actions included former Treasury Secretary Henry Paulson's request to Congress for $700 billion to buy distressed assets as part of a plan to halt what has been described as the worst financial crisis since the 1930's[20]. Amidst this turmoil, the Fed made the decision to cut the federal funds rate by another

[19] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008.

[20] 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.

50 basis points in a coordinated move with foreign central banks on October 8, 2008. This was followed by another 50 basis point cut during the regular FOMC meeting on October 29, 2008. At the time of this writing, the federal funds target rate now stands at 0.25 percent, the result of a 75 basis point cut announced on December 16, 2008.

Q. Has the Fed taken any further action to stimulate the economy?

Yes. At the close of the FOMC's September 2011 meeting the Fed announced its decision to implement a plan that resembles a 1961 Federal Reserve program known as "Operation Twist".[21] Under this plan, the Fed would sell $400 billion in Treasury securities that mature within three years. The proceeds from these sales would then be reinvested into securities that mature in six to 30 years. This action would significantly alter the balance of the Fed's holdings toward long-term securities. In addition to selling off its shorter term Treasury holdings, the proceeds from the Fed's maturing mortgage-backed securities would be reinvested in other mortgage backed securities. Since 2010, the Fed had been reinvesting that money into Treasury bonds, shrinking its mortgage portfolio. The overall goal of the Fed's plan was to reduce long-term interest rates in the hope of boosting investment and spending and

[21] Hilsenrath, Jon and Luca Di Leo "Fed Launches New Stimulus" The Wall Street Journal, September 22, 2011.

provide a shot in the arm to the beleaguered housing sector of the economy.

Q. Has there been any noticeable drop in long-term rates since the Fed announced its plan to purchase longer term Treasury instruments?

A. Yes. As can be seen on Schedule WAR-8, the yields on 30-year Treasury bonds have from fallen from an average of 4.08 percent during 2009 to the current yield of 3.10 percent.

Q. What is the current rate of inflation in the U.S.?

A. As can also be seen on Schedule WAR-8, the current rate of inflation, as measured by the consumer price index, is currently at 1.70 percent according to information provided by the U.S. Department of Labor's Bureau of Labor Statistics.[22]

Q. Has the Fed raised interest rates in anticipation of higher inflation?

A. No. The FOMC has not raised interest rates to date. The Fed's plan to buy $600 billion of U.S. government bonds over an eight month period, known as quantitative easing stage two or QE2,[23] was completed during the summer of 2011. The attempt to drive down long-term interest rates

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[22] http://www.bls.gov/news.release/cpi.nr0.htm

[23] Hilsenrath, Jon, "Fed Fires $600 Billion Stimulus Shot" The Wall Street Journal, November 4, 2010.

and encourage more borrowing and growth by increasing the money supply has yet to stimulate the economy and fears of a possible slide into recession persist.

At its January 30th and 31st 2013 meeting, the FOMC decided to keep purchasing $85 billion a month of mortgage-backed and Treasury securities and signaled no intention, for now, to stop.[24] The rate-setting body also reaffirmed its commitment to keep short-term rates near zero until unemployment drops to 6.5% from the current 7.8%. However, that depends on inflation holding to within a half percentage point of the Fed's 2.00 percent target. The FOMC further stated that it had decided to keep the target range for the federal funds rate at 0.00 to 0.25 percent. After its meeting the Fed stated that "Growth in economic activity paused in recent months." According to the Wall Street Journal, a separate government report issued on January 30, 2013 showed the economy contracted at a 0.1% annual rate in the fourth quarter. Fed officials attributed the stall to "weather-related disruptions and other transitory factors." Though they foresee a pickup to "moderate" growth, officials said they saw continued "downside risks to the economic outlook."

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[24] Hilsenrath, Jon and Victoria McGrane, "No Surprise as Fed Keeps Rate Stance" The Wall Street Journal, January 30, 2013.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected the yields on Treasury Instruments and benchmark interest rates?

A. As can be seen on Schedule WAR-8, current Treasury yields are considerably lower than corresponding yields that existed during the year 2000 and U.S. Treasury instruments, are for the most part, still at historically low levels. As can be seen on the first page of Attachment D, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has remained steady at 0.75 percent since November of 2011.

As of January 16, 2013, leading interest rates that include the 3-month, 6-month and 1-year treasury yields have only increased 4 to 5 basis points from their January 2012 levels. Longer term yields including the 5-year, 10-year and 30-year have either fallen or increased modestly from levels that existed a year ago. The same is true for the 30-year Zero rate. The prime rate has remained constant at 3.25 percent over the past year, as has the benchmark federal funds rate discussed above. 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

[25] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005.

completely reversed and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists.

Q. What are the current yields on utility bonds?

A. Referring again to Attachment D, as of January 16, 2013, 25/30-year A-rated utility bonds were yielding 3.96 percent (37 basis points lower than a year ago) and 25/30-year Baa/BBB-rated utility bonds were yielding 4.31 percent (down 63 basis points from a year earlier).

Q. How has the current environment of low interest rates impacted the returns on utilities in general?

A. In the November 2, 2012 Value Line quarterly update on the Electric Utility (West) Industry, Value Line analyst Paul E. Debbas, CFA had this to say on the effects of interest rates on utilities:

> "Since 2008, interest rates have been low as a result of Federal Reserve policy. This has had various effects on utilities (and their stocks). Some of these effects are positive, some negative. The most noticeable effect on utilities is reflected in their stock prices. With interest rates on savings accounts, money market funds, and other income vehicles minuscule, many investors have chosen to turn to income stocks. Utilities are known for paying healthy dividends. Indeed, at 4.1%, this industry's average yield is well above the median yield of all dividend-paying equities under our coverage. Low interest rates also reduce utilities' borrowing costs—something that is important in such a capital-intensive sector. Interest savings from refinancing debt will eventually be passed on to customers once the utility receives a rate order. However, for debt held at the parent level or at a non-utility subsidiary, the company retains any interest reductions. Low interest rates also have some negative aspects for this industry. Allowed returns on equity have been

> trending down due to declining interest rates. Also, low interest rates increase a company's pension obligations because they are discounted at a lower rate. This can be reflected in higher pension expense. Finally, Hawaiian Electric Industries is unique in this group due to its ownership of American Savings Bank. Low interest rates are squeezing the interest-rate spreads for thrifts."

Q. What is the current outlook for the economy?

A. The current outlook on the economy takes into consideration the recent resolution of the so called fiscal cliff situation (which involved the scheduled expiration of Bush Administration-era tax cuts and scheduled federal spending cuts) between the Executive Branch and Congress. Value line's analysts offered this perspective on the economy in the January 25, 2013 edition of Value Line's <u>Selection and Opinion</u> publication:

> "**This year is starting out in much the same way that 2012 ended,** that is, with the economy pushing forward in fits and starts. For example, the early part of 2013 has brought halting strides in employment, better gains in retail spending, a ballooning in the trade deficit, and modest increases in industrial production and factory use. It would seem from the above that the first quarter of the new year will see the nation's gross domestic product gain in the neighborhood of 1.5%."

Value Line's analysts went on to say:

> "**Overall, we look for progress to remain irregular through at least midyear.** To wit, we're likely to see growth step up to about 2%, or so, in the spring, before averaging close to 2.5% during the back half of the year. This forecast assumes that housing will pick up additional momentum, that the trends in capital investment, employment, inflation, and consumer spending will be generally positive, and that higher payroll taxes from a rise in withholdings for social security will not lead to a sustained setback in consumer confidence.

Value Line's analysts further stated:

> "**Washington remains a wild card,** with the deadlines for reaching a deal on spending cuts and the debt ceiling just weeks away. Unfortunately, little is happening on those fronts at this time. However, this might just be the calm before the inevitable storm that evolves before these vexing matters are finally settled."

Q. How are water utilities faring in the current economic environment?

A. While, as always, there are concerns regarding long-term infrastructure requirements, it appears that water utilities continue to be viewed as safe havens during the current period of economic uncertainty. In his January 18, 2013 quarterly water industry update (Attachment A) Value Line analyst Andre J. Costanza stated the following:

> "The Water Utility Industry has remained a hotbed of investor activity, with Wall Street continuing to pour money into the sector since our October review. As a result, the group now sits in the upper echelons of the Value Line Investment Survey for Timeliness, ranking 4th out of the 98 industries we analyze. It was ranked 28th three months ago and 54th back in July.
>
> Sentiment has been steadily improving, with the industry continuing to see interest from investors with concerns about the broader-based economy. Although the highly anticipated fiscal cliff appears to have been averted for now, global economies have been slow to improve, and in some cases, appear years away from turning the corner. Water utility stocks have historically done well during times of economic uncertainty, with their dividends providing some shelter.
>
> The recent spike in attention is warranted by company-specific fundamentals, too, though. Nearly every water provider in our Survey posted record earnings in the September quarter. (Note that none of the companies had released December-period results as of the writing of this report.

> That said, industry conditions are likely to stiffen going forward. Although the regulatory environment ought to remain favorable, and be a big help with costs, providers will be left holding sizable tabs, nonetheless. Unfortunately, most operating in this space lack the cash balances to meet the capital requirements that loom."

Q. How has Arizona fared in terms of the overall economy and home foreclosures?

A. Arizona was one of the states hit hardest during the Great Recession and has lagged during the current recovery.[26] During the period between 2006 and 2009, statewide construction spending fell by 40.00 percent. According to Irvine, California-based RealtyTrac's year-end report released on January 16, 2013, Arizona's 2.69 percent home foreclosure rate dropped to the No. 3 spot in the nation last year after three consecutive years of holding strong at No. 2. [27] RealtyTrac ranked Arizona third in the nation behind Florida and Nevada in terms of home foreclosures.[28]

...

[26] Beard, Betty, "Recession hit Arizona hardest" The Arizona Republic, March 6, 2011.

[27] Hansen, Kristena: "RealtyTrac - Arizona's home foreclosure rate improves (slightly)," Phoenix Business Journal, January 16, 2013.

[28] http://www.realtytrac.com/content/foreclosure-market-report/2012-year-end-foreclosure-market-report-7547

Q. What is the current unemployment situation in Arizona during this period of economic recovery?

A. According to information published on January 31, 2013, and displayed on the website of the Arizona Department of Administration's Office of Employment and Population Statistics,[29] the seasonally adjusted unemployment rate for Arizona remained steady at 7.90 percent in December 2012. At the time that this information was compiled, Arizona's rate of unemployment mirrored the U.S. unemployment rate of 7.90 percent.[30]

According to the January 17, 2013 Arizona Department of Administration's Office of Employment and Population Statistics report, the December 2011 rates of unemployment by county as follows:

[29] Arizona Department of Administration's Office of Employment and Population Statistics http://www.workforce.az.gov/

[30] U.S. Bureau of Labor Statistics Economic News Release dated June 3, 2011 http://www.bls.gov/news.release/empsit.nr0.htm

County Unemployment Rates - December 2012

Apache	18.7%
Cochise	7.8%
Coconino	8.4%
Gila	9.3%
Graham	8.6%
Greenlee	6.3%
La Paz	9.2%
Maricopa	6.6%
Mohave	9.5%
Navajo	14.8%
Pima	6.9%
Pinal	8.3%
Santa Cruz	16.5%
Yavapai	8.6%
Yuma	27.3%

Q. After weighing the economic information that you've just discussed, do you believe that the 8.75 percent cost of equity capital that you have estimated is reasonable for the Company?

A. I believe that my recommended 8.75 percent cost of equity capital, which is 444 basis points higher than the current 4.31 percent yield on a Baa/BBB-rated utility bond, will provide AWC with a reasonable rate of return on invested capital when data on interest rates (that are low by historical standards), the current state of the economy, current rates of unemployment (both nationally and in Arizona), and the Fed's decision to keep interest rates at their current levels for the foreseeable future 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 just below the high side of the range of results I obtained from 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 6.82 percent which is 193 basis points lower than my 8.75 percent recommended cost of equity capital.

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 48.95 percent long-term debt and 51.05 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 heavier in equity than the capital structures of the water utilities in my sample and would be perceived by investors as having lower financial risk. The capital structures for my sample of water utilities averaged 54.10 percent for debt and 45.90 percent for equity (45.7 percent common equity + 0.2 percent preferred equity). On the other hand, AWC has a slightly lower amount of equity than does the capital structures of the LDCs in my sample. The capital structures for those utilities averaged 49.60 percent for debt and 50.4 percent for equity (50.3 percent common equity + 0.1 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 48.95 percent long-term debt and 51.05 percent common equity.

WEIGHTED AVERAGE COST OF CAPITAL

Q. How does the Company's proposed weighted average cost of capital compare with your recommendation?

A. The Company has proposed a weighted average cost of capital of 9.11 percent. This figure is the result of a weighted average of AWC's proposed 6.82 percent cost of long-term debt and 11.30 percent cost of common equity capital. The Company-proposed 9.11 percent weighted cost of capital is 130 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, Ms. Pauline Ahearn, is recommending a cost of common equity of 11.30 percent. Her 11.30 percent cost of equity capital is 255 basis points higher than the 8.75 percent cost of equity capital that I am recommending.

Q. Briefly summarize Ms. Ahearn's direct testimony.

A. A good portion of Ms. Ahearn's testimony is devoted to justifying AWC's request for a DSIC mechanism which I have discussed in a separate piece of direct testimony that I have filed in this proceeding. The remainder of her testimony explains the various models and inputs that she used to obtain her cost of common equity recommendation.

...

Q. What methods did Ms. Ahearn use to arrive at her cost of common equity for AWC?

A. Ms. Ahearn utilized the DCF, the CAPM and a risk premium methodology which I have not employed. Ms. Ahearn relies on the same single stage DCF model that I have used. Her CAPM analysis includes two versions of the CAPM both the Sharpe Litner version that I have relied on and the ECAPM which the Commission has rejected in prior cases.

DCF Comparison

Q. Briefly compare the results of Ms. Ahearn's DCF analysis with the results your DCF analysis.

A. Ms. Ahearn's DCF analysis produced a median average of 9.13 percent for the water companies in her sample, which she relied on in making her final cost of common equity recommendation, and a mean average of 10.02 percent. My DCF analysis produced estimates of 8.75 percent for LDCs, and 7.97 percent for water companies.

Q. Please compare the dividend yield results that you obtained from your DCF analysis and the results that Ms. Ahearn obtained from her DCF analysis using the constant growth model?

A. Referring our exhibits PMA 7 and WAR-3, Ms. Ahearn obtained an average dividend yield (i.e. D_1 / P_0) of 3.11 percent over a 60-day observation period of closing stock prices (as opposed to my more recent

8-week observation period) for her sample of nine water utilities (as opposed to six water utilities in my sample). She then makes an upward adjustment to her 60-day average dividend yield by multiplying it times a factor of 1 plus 50.00 percent of an average of analysts' 5-year earnings per share projections as opposed to annualizing the most recently declared dividend as I have. The difference between her average dividend yield of 3.40 percent and my average dividend yield of 3.07 percent, which is based on more current information, is 33 basis points. A comparison of her average of the six utilities that our water samples have in common yields a difference of 38 basis points (3.45 percent - 3.07 percent = 0.38 percent). The difference between her water utility dividend yield estimate of 3.40 percent and my LDC dividend yield estimate of 3.84 percent is 44 basis points (3.84 percent - 3.40 percent = 0.44 percent).

Q. Are there other reasons that would explain the difference in your respective dividend yield estimates?

A. Yes. As always, timing plays a role. Ms. Ahearn's dividend yield calculation was performed using 60 day's worth of closing stock price information that was current as of July 6, 2012. This resulted in an average adjusted stock price of $23.78 for the nine water utilities in her sample. The average adjusted stock price of the six water utilities that our samples have in common was $25.09 at that point in time as opposed to my more recent average adjusted price of $29.17 for the 8-week period that ended on January 25, 2013. Clearly the average adjusted price of the water utilities that our samples have in common has increased since Ms. Ahearn conducted her DCF analysis almost seven months ago. The lower stock prices and higher adjusted dividends used by Ms. Ahearn would produce higher results than my DCF inputs.

Q. Does your comparison of the difference in average adjusted stock prices reveal anything else?

A. Yes. I believe it supports Value Lines's opinion that "the Water Utility Industry has remained a hotbed of investor activity, with Wall Street continuing to pour money into the sector" and that the water utility industry is seeing "interest from investors with concerns about the broader-based economy." If Value Line is correct in its opinion, the demand for water company stocks, from investors seeking safer investment opportunities in the current market environment, are driving up their prices. The dividend yields, which are attractive when compared to the lower yields on Treasury instruments, and the perceived safety of the investment, would also explain the increase in price. This being the case, as I have stated in prior proceedings, water companies such as AWC do not need higher rates of return to attract investors at this point in time.

...

Q. How does Ms. Ahearn's DCF growth estimate (g) compare with your growth estimates for water utilities?

A. Ms. Ahearn's analysis produced an average water company growth estimate of 6.62 as opposed to my growth estimate of 4.90 percent for both the water companies and LDCs that were included in my two samples.

Q. Can you explain the differences in your methods for obtaining your respective growth estimates?

A. Yes. Ms. Ahearn's higher 6.62 percent water company growth rate was obtained by averaging only the 5-year earnings per share projections of analysts from Value Line, Reuters, Zacks and Yahoo Finance. As I explained earlier in my direct testimony, I obtained my growth estimates by evaluating a larger number of metrics which included Value Line growth projections for both internal and external growth (based on retained earnings, returns on book common equity projections and shares outstanding for 2012 through 2017), and on future growth in earnings, dividends and book value per share (Schedule WAR 5 pages 1 through 5 and Attachments A and B) and then comparing them to current Zacks earnings per share estimates and Value Line estimates of earnings per share, dividends per share and book value per share for the companies included in my water and gas samples (Schedule WAR-6).

CAPM Comparison

Q. What were the results of Ms. Ahearn's CAPM analysis and your CAPM analysis?

A. Ms. Ahearn is recommending an expected return of 11.01 percent as opposed to my water company sample expected returns that range from 5.79 percent to 6.90 percent, and my LDC sample expected returns that range from 5.64 percent to 6.69 percent.

Q. Compare the way that Ms. Ahearn and you arrived at your expected rates of return using the CAPM.

A. Ms. Ahearn's averaged the results she obtained from the traditional CAPM and ECAPM to obtain a median average expected rate of return of 11.01 percent, which she relied on in making her final cost of common equity recommendation, and a mean average expected rate of return of 11.30 percent. Her 11.01 percent estimate is 411 basis points to 522 basis points higher than my 6.90 percent and 5.79 percent expected rate of return results for water companies using the traditional CAPM and relying on arithmetic and geometric means (to calculate the market risk premium) respectively. Ms. Ahearn's 11.01 percent estimate is 432 basis points to 537 basis points higher than my 6.69 percent and 5.64 percent expected rate of return results for LDCs using the traditional CAPM and relying on arithmetic and geometric means (to calculate the market risk premium) respectively.

Q. What is the difference between the risk-free instrument that Ms. Ahearn used in her CAPM model and the one that you used?

A. Ms. Ahearn's 4.26 percent risk-free rate of return is 131 basis points higher than my 2.95 percent risk-free rate of return which is an 8-week average of the yield on a 30-year U.S. Treasury instrument.

Q. How did Ms. Ahearn calculate her risk-free rate of return?

A. Ms. Ahearn averaged the 5.32 percent historical return on long-term treasuries, from 1926 to 2011, with a 3.20 percent average of six quarters of forecasted yields on a 30-year U.S. Treasury instrument.

Q. What are your concerns with Ms. Ahearn's use of forecasted yields on long-term U.S. Treasury instruments for a risk-free rate of return?

A. Besides the fact that Ms. Ahearn 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 and have only used the 30-year yield for the sake of argument in this case. As I stated earlier in my testimony, utilities in Arizona typically file for rates every three to five years. Because of this, a good argument can be made that the yield on a 5-year U.S. Treasury Instrument is a better proxy for a risk-free rate of return. That aside, I further believe that the best indicator for future yields are the most recent yields on U.S. treasury instruments.

Furthermore, Ms. Ahearn's method totally ignores the fact that the Federal Reserve intends to keep interest rates at their current low levels through 2014.

Q. How did Ms. Ahearn's average beta used in her CAPM model compare with the average beta that you used in yours?

A. Despite the different companies included in our samples, Ms. Ahearn's average water company beta of 0.68 falls between my average betas of 0.69 and 0.66 for my water company sample and LDC sample respectively.

Q. How does Ms. Ahearn's market risk premium compare with the market risk premium that you used in your CAPM analysis?

A. Ms. Ahearn's market risk premium of 9.73 percent is 403 to 563 basis points higher than my risk premiums of 5.70 percent using an arithmetic mean and 4.10 percent using a geometric mean.

Q. How did Ms. Ahearn calculate her market risk premium of 9.73 percent?

A. I will not even begin to attempt to explain the almost Byzantine methodology that Ms. Ahearn has employed to arrive at her unrealistically high market risk premium of 9.73 percent. I will however say that Ms.

Ahearn rejects the use of geometric means to calculate the market risk premium component of the CAPM.

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."

Q. How did Ms. Ahearn arrive at her final 11.30 percent cost of common equity for AWC?

A. Ms. Ahearn's final estimate of 11.30 percent is the sum of a 10.34 percent average of the results of her various DCF, CAPM and risk premium methodologies, a 0.50 percent credit risk adjustment and a 0.45 percent business risk adjustment.

...

Q. Do you believe that AWC requires a 0.50 percent credit risk adjustment?

A. No. AWC has successfully placed its various bond issuances in the past. In fact, Mr. Harris, the Company's Vice President and Treasurer testified under oath during a prior AWC rate case hearing that the Company's most recent bond issuance was placed with an insurance company – a business which has been traditionally viewed as risk averse.

Q. Do you agree with Ms. Ahearn's assertion that AWC needs a 0.45 basis point adjustment for business risk?

A. No. Each of the Companies used in my water sample are essentially a collection of water systems such as the ones that make up AWC. These systems face the same type of risks faced by AWC and investors' tolerance for those types of risk are reflected in the cost of equity capital derivied from my analysis. I believe that my 8.75 percent cost of equity, which is 193 basis points higher than the Company's cost of debt, mitigates any perceived business risk that is unique to AWC.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Ms. Ahearn 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.

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:

Chief of Accounting and Rates
Residential Utility Consumer Office
October 2011 – Present

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

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

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

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

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
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-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	WS-01303A-06-0491	Rate Increase
UNS Electric, Inc.	E-04204A-06-0783	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 Public Service Company	E-01345A-08-0172	Rate Increase
Johnson Utilities, LLC	WS-02987A-08-0180	Rate Increase
Arizona-American Water Company	W-01303A-08-0227 et al.	Rate Increase

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
UNS Gas, Inc.	G-04204A-08-0571	Rate Increase
Arizona Water Company	W-01445A-08-0440	Rate Increase
Far West Water & Sewer Company	WS-03478A-08-0608	Interim Rate Increase
Black Mountain Sewer Corporation	SW-02361A-08-0609	Rate Increase
Global Utilities	SW-02445A-09-0077 et al.	Rate Increase
Litchfield Park Service Company	SW-01428A-09-0104 et al.	Rate Increase
UNS Electric, Inc.	E-04204A-09-0206	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-09-0257	Rate Increase
Arizona-American Water Company	W-01303A-09-0343	Rate Increase
Bella Vista Water Company	W-02465A-09-0411 et al.	Rate Increase
Chaparral City Water Company	W-02113A-10-0309	Reorganization
Qwest Communications International	T-04190A-10-0194 et al.	Merger
CenturyLink, Inc.	T-04190A-10-0194 et al.	Merger
Southwest Gas Corporation	G-01551A-10-0458	Rate Increase
Arizona-American Water Company	W-01303A-10-0448	Rate Increase
Arizona-American Water Company	W-01303A-11-0101	Reorganization
Arizona-American Water Company	W-01303A-09-0343	Deconsolidation
Goodman Water Company	W-02500A-10-0382	Rate Increase
Arizona Water Company	W-01445A-10-0517	Rate Increase
Bermuda Water Company, Inc.	W-01812A-10-0521	Rate Increase
UNS Gas, Inc.	G-04204A-11-0158	Rate Increase
Arizona Public Service Company	E-01345A-11-0224	Rate Increase
Arizona Water Company	W-01445A-11-0310	Rate Increase
Pima Utility Company	W-02199A-11-0329 et al.	Rate Increase
Tucson Electric Power Company	E-01933A-12-0291	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-12-0196	Rate Increase

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Far West Water & Sewer, Inc.	WS-02676A-12-0196	Rate Increase

ATTACHMENT A

INDUSTRY TIMELINESS: 4 (of 98)

The Water Utility Industry has remained a hotbed of investor activity, with Wall Street continuing to pour money into the sector since our October review. As a result, the group now sits in the upper echelons of the *Value Line Investment Survey* for Timeliness, ranking 4th out of the 98 industries we analyze. It was ranked 28th three months ago and 54th back in July.

Sentiment has been steadily improving, with the industry continuing to see interest from investors with concerns about the broader-based economy. Although the highly anticipated fiscal cliff appears to have been averted for now, global economies have been slow to improve, and in some cases, appear years away from turning the corner. Water utility stocks have historically done well during times of economic uncertainty, with their dividends providing some shelter.

The recent spike in attention is warranted by company-specific fundamentals, too, though. Nearly every water provider in our *Survey* posted record earnings in the September quarter. (Note that none of the companies had released December-period results as of the writing of this report.

That said, industry conditions are likely to stiffen going forward. Although the regulatory environment ought to remain favorable, and be a big help with costs, providers will be left holding sizable tabs, nonetheless. Unfortunately, most operating in this space lack the cash balances to meet the capital requirements that loom.

Industry Basics

One of, if not the, biggest essentials to sustaining just about any life form, water demand is undeniable. As a result, demand will probably continue to grow along with the population, with the only other major determinant being weather conditions. Given water's necessity, each individual state has a regulatory body in place that is responsible for the safe and timely delivery of water as well as for maintaining a balance of power between providers and customers. Recently, regulators have become far more business-friendly, handing down more favorable rulings on general rate cases and allowing providers to recoup some of the growing costs of operating a utility. State regulators review and rule on general rate case requests submitted by providers looking to recover costs incurred during distribution, and therefore are vital to each company's future. Every provider has a lot riding on the cases under review.

Swimming In Expenses

Despite the improved regulatory environment, water providers are still left holding the bill for most of the infrastructure improvements that need to be made. And that can be substantial amounts of cash in this space, given the age and conditions of many of these infrastructures. However, the majority of those operating here lack the finances to fund the improvements on their own, and are forced to look to outside financiers in order to meet the capital requirements. Although external financing has become commonplace, the increased shares and or debt taken on in order to finance the upgrades are eating away at profits and diluting shareholder gains.

The extravagant costs have spurred significant M&A activity, with those not willing or capable of raising the necessary capital shopping themselves, looking for larger, better equipped suitors. More capable players, such as *Aqua America* have been taking advantage of this trend, using the spike in activity to grow their businesses and expand their footprints.

Conclusion

There remains a couple of timely plays in this group. Momentum investors will probably be interested in *American States Water, SJW Corp.*, and *Aqua America*, all of which rank 2 (Above Average) thanks to recent earnings power. *American* and *Aqua*, meanwhile, also score favorably (2: Above Average) for Safety, adding to their appeal on a risk-adjusted basis.

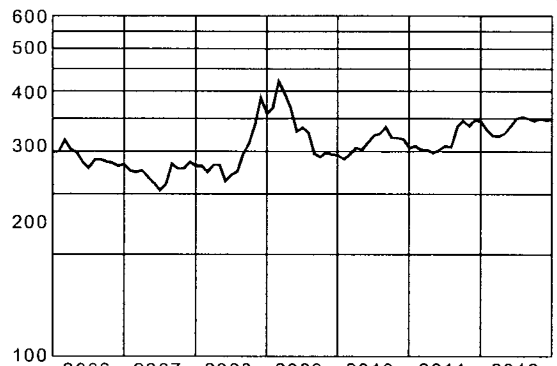
That said, not a single issue holds worthwhile price appreciation potential out to mid-decade. The capital-intensive nature of this business, coupled with financial constraints, spell trouble for the future gains of those in this space. Indeed, maintenance costs alone are expected to cost operators hundreds of millions of dollars each year.

Even still, the industry's main draw has long been its income component. All of the stocks here offer above average dividend yields and appear to be worthy of consideration for those looking to add a steady income producer to their portfolios at first blush. However, deeper evaluation gives us some pause regarding the sustainability of these yields long term with our concerns about the rising costs of doing business and inadequate finances threatening to offset any benefits from regulatory improvements. As such, we believe that there are better income vehicles elsewhere, particularly in the Electric Utility Industry. Nevertheless, as always, we advise potential investors to carefully review the individual reports of each stock in the group, with a keen eye on company finances and future cash flow. Both will be very telling heading forward, especially if regulators take a more consumer friendly approach. Investors ought to note that *Connecticut Water Service*, is making its inaugural appearance in our *Survey*.

Andre J. Costanza

Water Utility

RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)



Index: June, 1967 = 100

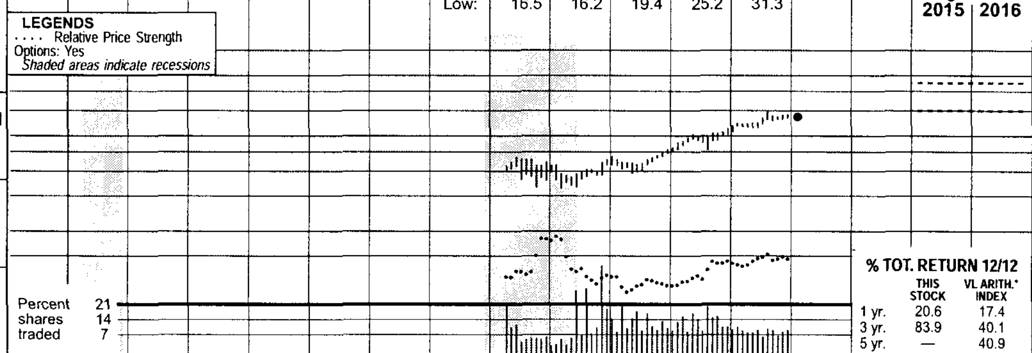
AMERICAN WATER NYSE-AWK

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
37.33	16.4 (Trailing: 17.9 Median: NMF)	1.04	2.7%	VALUE LINE

TIMELINESS 3 Lowered 12/28/12
SAFETY 3 New 7/25/08
TECHNICAL 3 Raised 1/4/13
BETA .65 (1.00 = Market)

	High:	23.7	23.0	25.8	32.8	39.4
	Low:	16.5	16.2	19.4	25.2	31.3

Target Price Range
2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+45%)	13%
Low	40	(+5%)	5%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	7	0	2	1	0	5	0	0
to Sell	0	7	0	2	0	0	6	0	0

Institutional Decisions

	1Q2012	2Q2012	3Q2012
to Buy	164	176	173
to Sell	163	162	171
Hld's(000)	141669	140028	143865

% TOT. RETURN 12/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.6	17.4
3 yr.	83.9	40.1
5 yr.	—	40.9

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
--	--	--	--	--	--	--	--	--	--	13.08	13.84	14.61	13.98	15.49	15.18	*16.40*	*16.55*	Revenues per sh	*18.60*
--	--	--	--	--	--	--	--	--	--	.65	d.47	2.87	2.89	3.56	3.74	*4.30*	*4.40*	"Cash Flow" per sh	*4.80*
--	--	--	--	--	--	--	--	--	--	d.97	d2.14	1.10	1.25	1.53	1.72	*2.20*	*2.25*	Earnings per sh A	*2.50*
--	--	--	--	--	--	--	--	--	--	--	--	.40	.82	.86	.91	.96	*1.04*	Div'd Decl'd per sh B■	*1.25*
--	--	--	--	--	--	--	--	--	--	4.31	4.74	6.31	4.50	4.38	5.27	*5.10*	*5.30*	Cap'l Spending per sh	*5.05*
--	--	--	--	--	--	--	--	--	--	23.86	28.39	25.64	22.91	23.59	24.14	*25.20*	*25.60*	Book Value per sh D	*27.15*
--	--	--	--	--	--	--	--	--	--	160.00	160.00	160.00	174.63	175.00	175.66	*177.00*	*180.00*	Common Shs Outst'g C	*188.00*
--	--	--	--	--	--	--	--	--	--	--	--	18.9	15.6	14.6	16.7	*16.0*		Avg Ann'l P/E Ratio	*19.0*
--	--	--	--	--	--	--	--	--	--	--	--	1.14	1.04	.93	1.05	*1.01*		Relative P/E Ratio	*1.25*
--	--	--	--	--	--	--	--	--	--	--	--	1.9%	4.2%	3.8%	3.1%	2.7%		Avg Ann'l Div'd Yield	*2.8%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $5535.9 mill. **Due in 5 Yrs** $229.5 mill.
LT Debt $5203.1 mill. **LT Interest** $306.5 mill.
(Total interest coverage: 4.3x) (54% of Cap'l)

Leases, Uncapitalized: Annual rentals $21.5 mill.
Pension Assets-12/11 $981.1 mill
Oblig. $1402.0 mill.
Pfd Stock $19.3 mill. **Pfd Div'd** $.7 mill

Common Stock 176,756,790 shs.
as of 11/1/12

MARKET CAP: $6.6 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
--	--	--	--	2093.1	2214.2	2336.9	2440.7	2710.7	2666.2	*2900*	*2975*	Revenues ($mill)	*3500*
--	--	--	--	d155.8	d342.3	187.2	209.9	267.8	304.9	*390*	*400*	Net Profit ($mill)	*470*
--	--	--	--	--	--	37.4%	37.9%	40.4%	39.5%	*40.0%*	*40.0%*	Income Tax Rate	*39.0%*
--	--	--	--	--	--	--	--	12.5%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*15.0%*
--	--	--	--	56.1%	50.9%	53.1%	56.9%	56.8%	55.6%	*53.5%*	*54.0%*	Long-Term Debt Ratio	*53.0%*
--	--	--	--	43.9%	49.1%	46.9%	43.1%	43.2%	44.2%	*46.5%*	*46.0%*	Common Equity Ratio	*47.0%*
--	--	--	--	8692.8	9245.7	8750.2	9289.0	9561.3	9601.5	*9650*	*9995*	Total Capital ($mill)	*10850*
--	--	--	--	8720.6	9318.0	9991.8	10524	11059	11021	*11550*	*12105*	Net Plant ($mill)	*13700*
--	--	--	--	NMF	NMF	3.7%	3.8%	4.4%	4.7%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
--	--	--	--	NMF	NMF	4.6%	5.2%	6.5%	7.2%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
--	--	--	--	NMF	NMF	4.6%	5.2%	6.5%	7.2%	*8.5%*	*8.5%*	Return on Com Equity	*9.0%*
--	--	--	--	NMF	NMF	3.0%	1.8%	2.8%	3.5%	*5.0%*	*4.5%*	Retained to Com Eq	*4.5%*
--	--	--	--	--	--	34%	65%	56%	52%	*44%*	*47%*	All Div'ds to Net Prof	*51%*

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	13.1	14.2	18.5
Other	521.2	1383.5	622.0
Current Assets	534.3	1397.7	642.5
Accts Payable	199.2	243.7	202.3
Debt Due	44.8	543.9	332.8
Other	530.5	701.5	460.8
Current Liab.	774.5	1489.1	1005.9
Fix. Chg. Cov.	237%	256%	300%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	--	--	4.0%
"Cash Flow"	--	--	6.0%
Earnings	--	--	9.0%
Dividends	--	--	6.5%
Book Value	--	--	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	550.2	612.7	680.0	597.8	2440.7
2010	588.1	671.2	786.9	664.5	2710.7
2011	596.7	668.8	760.9	639.8	2666.2
2012	618.6	745.6	831.8	*704*	*2900*
2013	*650*	*750*	*850*	*725*	*2975*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.19	.32	.52	.21	1.25
2010	.18	.42	.71	.23	1.53
2011	.23	.42	.73	.34	1.72
2012	.28	.66	.87	*.39*	*2.20*
2013	*.34*	*.68*	*.84*	*.39*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.20	.20	.21	.21	.82
2010	.21	.21	.22	.22	.86
2011	.22	.23	.23	.23	.91
2012	.23	.23	.25	.25	.96
2013					

BUSINESS: American Water Works Company, Inc. is the largest investor-owned water and wastewater utility in the U.S., providing services to over 15 million people in over 30 states and Canada. Its nonregulated business assists municipalities and military bases with the maintenance and upkeep as well. Regulated operations made up 88.9% of 2011 revenues. New Jersey is its biggest market accounting for 20.9% of revenues. Has roughly 7,000 employees. Depreciation rate, 2.5% in '11. BlackRock, Inc., owns 7.4% of the common stock outstanding. Off. & dir. own less than 1% (3/12 Proxy). President & CEO; Jeffry Sterba. Chairman; George Mackenzie. Address: 1025 Laurel Oak Road, Voorhees, NJ 08043. Telephone: 856-346-8200. Internet: www.amwater.com.

American Water Works probably closed out a successful 2012 campaign in impressive fashion. The water provider posted strong top- and bottom-line growth through the first nine months, as earlier portfolio optimization proved a benefit. Indeed, the company was able to add exposure to flourishing systems, while removing positions in less profitable areas. Perhaps just as important, however, was management's ability to control costs while doing so. We suspect that the company posted 15% share-net growth, on a 10 % revenue gain in the fourth quarter.

Earnings growth will probably be far more difficult to come by this year, however. Although we believe that the top line will continue to benefit from favorable regulatory rulings and the improved portfolio mix, it is hard to imagine that the cost base will not rise going forward. Indeed, the company is slated to make a number of infrastructure upgrades to aging systems. Thus, we look for costs to begin to mount, thereby cutting into margins, despite efforts to keep expenses under wraps.

Financing is likely to become a concern again. Aside from the benefits mentioned above, the portfolio optimization effort gave American Water some financial flexibility last year. However, most of that cash probably has been burned through by now, and cash on hand is minimal, so the company will have to seek outside financing in order to fund the aforementioned upgrades. But any debt and/or share offerings will dilute earnings.

This stock is not overly appealing at this time. It is no longer timely, and the capital-intensive nature of the business threatens to stymie earnings growth for the foreseeable future. The balance sheet is highly leveraged and is likely to only get worse as the company is expected to spend some $900 million per annum to make infrastructure repairs. Operational cash flow will not be sufficient to make the changes, requiring American Water to float additional debt and shares, despite what we believe will be favorable regulatory backing. Overall, although the stock's income component is above average, there are better, more sustainable options to chose from, in our opinion.

Andre J. Costanza *January 18, 2013*

(A) Diluted earnings. Excludes nonrecurring losses: '08, $4.62; '09, $2.63; '11, $0.07. Discontinued operations: '06, (4¢); '11, 3¢; '12, (10¢).
Next earnings report due late Feb. Quarterly earnings may not sum due to rounding.
(B) Dividends paid in March, June, September, and December. ■ Div. reinvestment available.
(C) In millions.
(D) Includes intangibles. In 2011: $1.195 billion, $9.80/share.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	20

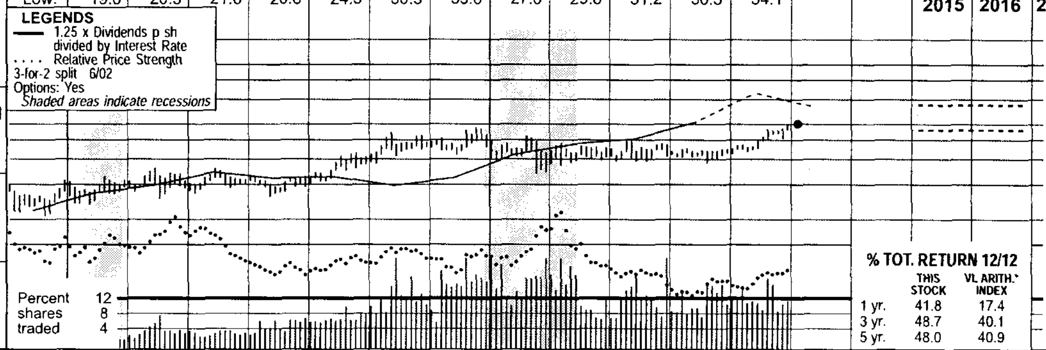
AMER. STATES WATER NYSE-AWR

RECENT PRICE	48.57	P/E RATIO	18.8 (Trailing: 18.3 / Median: 22.0)	RELATIVE P/E RATIO	1.19	DIV'D YLD	2.9%	VALUE LINE

TIMELINESS **2** Raised 11/23/12
SAFETY **2** Raised 7/20/12
TECHNICAL **3** Raised 1/4/13
BETA .70 (1.00 = Market)

High:	26.4	29.0	29.0	26.8	34.6	43.8	46.1	42.0	38.8	39.6	36.4	48.1	
Low:	19.0	20.3	21.6	20.8	24.3	30.3	33.6	27.0	29.8	31.2	30.5	34.1	

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+25%)	8%
Low	45	(-5%)	1%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	2	2	0	4	2	0	16	0	0
to Sell	2	2	0	4	2	0	17	0	0

Institutional Decisions

	1Q2012	2Q2012	3Q2012
to Buy	69	83	79
to Sell	63	50	65
Hld's(000)	11810	11968	11747

% TOT. RETURN 12/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	41.8	17.4
3 yr.	48.7	40.1
5 yr.	48.0	40.9

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
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	19.48	21.41	22.24	23.95	24.50	Revenues per sh	27.80
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	3.40	4.23	4.26	4.60	4.85	"Cash Flow" per sh	5.50
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	1.62	2.22	2.24	2.65	2.70	Earnings per sh A	2.80
.82	.83	.84	.85	.86	.87	.87	.88	.89	.90	.91	.96	1.00	1.01	1.04	1.10	1.27	1.45	Div'd Decl'd per sh B■	1.60
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	4.18	4.24	4.26	4.20	4.40	Cap'l Spending per sh	5.10
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	19.39	20.26	21.68	22.80	23.15	Book Value per sh	23.80
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	18.53	18.63	18.85	19.00	19.20	Common Shs Outst'g C	19.60
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	21.2	15.7	15.7	15.3		Avg Ann'l P/E Ratio	19.0
.79	.84	.81	.97	1.03	.86	1.00	1.82	1.23	1.17	1.50	1.27	1.36	1.41	1.00	1.01	.96		Relative P/E Ratio	1.25
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%	2.9%	3.0%	3.0%	3.1%		Avg Ann'l Div'd Yield	3.0%

CAPITAL STRUCTURE as of 9/30/12
Total Debt $344.4 mill. Due in 5 Yrs $280.0 mill.
LT Debt $344.2 mill. LT Interest $24.0 mill.
(LT interest earned: 5.5x: total interest coverage: 5.2x) (43% of Cap'l)

Leases, Uncapitalized: Annual rentals $3.3 mill.

Pension Assets-12/11 $92.9 mill. **Oblig.** $146.1 mill.

Pfd Stock None.

Common Stock 19,216,427 shs. as of 11/2/12

MARKET CAP: $925 million (Small Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
209.2	212.7	228.0	236.2	268.6	301.4	318.7	361.0	398.9	419.3	455	470	Revenues ($mill)	545
20.3	11.9	16.5	22.5	23.1	28.0	26.8	29.5	41.4	42.0	50.0	55.0	Net Profit ($mill)	55.0
38.9%	43.5%	37.4%	47.0%	40.5%	42.6%	37.8%	38.9%	43.2%	41.7%	42.5%	42.0%	Income Tax Rate	40.0%
--	--	--	--	12.2%	8.5%	6.9%	3.2%	5.8%	5.8%	5.0%	5.0%	AFUDC % to Net Profit	5.0%
52.0%	52.0%	47.7%	50.4%	48.6%	46.9%	46.2%	45.9%	44.3%	45.4%	43.0%	43.0%	Long-Term Debt Ratio	42.0%
48.0%	48.0%	52.3%	49.6%	51.4%	53.1%	53.8%	54.1%	55.7%	54.6%	57.0%	57.0%	Common Equity Ratio	58.0%
444.4	442.3	480.4	532.5	551.6	569.4	577.0	665.0	677.4	749.1	760	780	Total Capital ($mill)	805
563.3	602.3	664.2	713.2	750.6	776.4	825.3	866.4	855.0	896.5	935	980	Net Plant ($mill)	1080
6.5%	4.6%	5.2%	5.4%	6.0%	6.7%	6.4%	5.9%	7.6%	6.0%	6.0%	6.0%	Return on Total Cap'l	7.0%
9.5%	5.6%	6.6%	8.5%	8.1%	9.3%	8.6%	8.2%	11.0%	10.3%	10.5%	11.0%	Return on Shr. Equity	12.0%
9.5%	5.6%	6.6%	8.5%	8.1%	9.3%	8.6%	8.2%	11.0%	10.3%	10.5%	11.0%	Return on Com Equity	12.0%
3.3%	NMF	1.0%	2.8%	2.7%	3.9%	3.1%	3.2%	5.8%	5.2%	5.0%	5.0%	Retained to Com Eq	5.0%
65%	113%	84%	67%	67%	58%	64%	61%	47%	49%	48%	50%	All Div'ds to Net Prof	57%

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	4.2	1.3	43.1
Other	200.8	164.3	144.0
Current Assets	205.0	165.6	187.1
Accts Payable	36.2	37.9	52.1
Debt Due	61.3	.3	.2
Other	81.3	66.2	56.9
Current Liab.	178.8	104.4	109.2
Fix. Chg. Cov.	428%	401%	390%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	5.0%	7.5%	4.5%
"Cash Flow"	5.5%	9.5%	5.5%
Earnings	4.5%	11.5%	5.5%
Dividends	2.0%	2.5%	7.5%
Book Value	5.0%	5.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	79.6	93.6	101.5	86.3	361.0
2010	88.4	95.5	111.3	103.7	398.9
2011	94.3	109.8	119.9	95.3	419.3
2012	106.6	114.3	133.5	100.6	455
2013	105	120	135	110	470

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.28	.64	.52	.18	1.62
2010	.45	.47	.62	.68	2.22
2011	.37	.68	.83	.36	2.24
2012	.53	.79	.97	.36	2.65
2013	.50	.75	1.00	.45	2.70

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.250	.250	.250	.260	1.01
2010	.260	.260	.260	.260	1.04
2011	.260	.280	.280	.280	1.10
2012	.280	.280	.355	.355	1.27
2013					

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. Sold Chaparral City Water of Arizona (6/11). Has 703 employees. Officers & directors own 2.9% of common stock (4/12 Proxy). Chairman: Lloyd Ross. President & CEO: Robert J. Sprowls. Inc: CA. Addr: 630 East Foothill Boulevard, San Dimas, CA 91773. Tel: 909-394-3600. Internet: www.aswater.com.

American States Water's bottom-line momentum will likely slow a bit in 2013. We believe that share net grew 18% in 2012, largely due to the Contracted Services unit in its American States Utility Services (ASUS) subsidiary. ASUS continues to generate higher-than-expected construction margins on the Fort Bragg military base in North Carolina and on bases in Virginia. This subsidiary provides the most upside, as it takes on projects that are lighter on the regulatory front. The 50-year privatization contract with the U.S. government on Fort Bragg offers a decent amount of business going forward. Though optimism is strong, the reliability of future awards provides a greater concern. We expect difficult comps, and fewer projects will slow growth in this segment. Therefore, this expected softness in Contracted Services, coupled with flattish water and electric growth, have tempered our optimism for 2013.

Management's focus on bidding opportunities should bolster longer-term growth. We expect work on military bases will drive a majority of the company's bidding activity. One new venture that should get started in 2013 is the $18 million Patriot Project. The project includes construction of water and sewer infrastructure on a Fort Bragg addition. As mentioned, new work should be lumpy and provide some uncertainty for longer-term profitability. However, the newly initiated dividend from ASUS to AWR should ease some of investors' concerns.

The balance sheet continues to show improvement. AWR generated $43 million of free cash flow in the first nine months of 2012. This compares to the $1 million cash burn experienced for the same time frame in 2011. The company's cash position has strengthened to $43 million from $1 million reported at the start of 2012.

The Timeliness rank of this issue is 2 (Above Average). These shares should appeal to dividend-oriented accounts, as the stock offers an above-average yield when compared to the *Value Line* median and its peers. However, we advise longer-term investors to look elsewhere, due to the below-average capital appreciation potential.

Michael Collins *January 18, 2013*

(A) Primary earnings. Excludes nonrecurring gains/(losses): '04, 14¢; '05, 25¢; '06, 6¢; '08, (27¢); '10, (45¢) '11, 20¢. Next earnings report due early March. Quarterly egs. 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 split.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	90

CALIFORNIA WATER NYSE-CWT

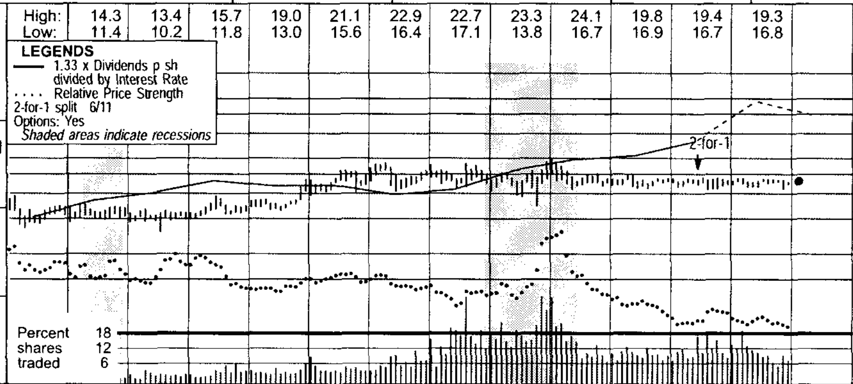
RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
18.58	18.6 (Trailing: 19.8 Median: 21.0)	1.18	3.4%

VALUE LINE

TIMELINESS 3 Raised 8/3/12
SAFETY 3 Lowered 7/27/07
TECHNICAL 3 Lowered 11/16/12
BETA .65 (1.00 = Market)

High:	14.3	13.4	15.7	19.0	21.1	22.9	22.7	23.3	24.1	19.8	19.4	19.3
Low:	11.4	10.2	11.8	13.0	15.6	16.4	17.1	13.8	16.7	16.9	16.7	16.8

Target Price Range
2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+60%)	15%
Low	20	(+10%)	5%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	19	0	2	0	0	1	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	1	0	0

Institutional Decisions

	1Q2012	2Q2012	3Q2012
to Buy	60	54	63
to Sell	55	53	46
Hld's(000)	22431	21505	22150

% TOT. RETURN 12/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.1	17.4
3 yr.	10.3	40.1
5 yr.	16.8	40.9

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
7.24	7.74	7.38	7.98	8.08	8.13	8.67	8.18	8.59	8.72	8.10	8.88	9.90	10.82	11.05	12.00	13.00	13.05	Revenues per sh	14.20
1.25	1.46	1.30	1.37	1.26	1.10	1.32	1.26	1.42	1.52	1.36	1.56	1.86	1.93	1.93	2.07	2.30	2.35	"Cash Flow" per sh	2.65
.75	.92	.73	.77	.66	.47	.63	.61	.73	.74	.67	.75	.95	.98	.91	.86	.97	1.05	Earnings per sh A	1.30
.52	.53	.54	.54	.55	.56	.56	.56	.57	.57	.58	.58	.59	.59	.60	.62	.63	.64	Div'd Decl'd per sh B ■	.72
1.41	1.30	1.37	1.72	1.23	2.04	2.91	2.19	1.87	2.01	2.14	1.84	2.41	2.66	2.97	2.83	3.00	3.20	Cap'l Spending per sh	3.05
6.11	6.50	6.69	6.71	6.45	6.48	6.56	7.22	7.83	7.90	9.07	9.25	9.72	10.13	10.45	10.76	11.35	11.60	Book Value per sh C	12.75
25.24	25.24	25.24	25.87	30.29	30.36	30.36	33.86	36.73	36.78	41.31	41.33	41.45	41.53	41.67	41.82	42.25	44.00	Common Shs Outst'g D	47.00
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	19.7	20.3	21.3	18.8		Avg Ann'l P/E Ratio	19.0
.75	.73	.93	1.01	1.27	1.39	1.08	1.26	1.06	1.33	1.58	1.39	1.19	1.31	1.29	1.34	1.18		Relative P/E Ratio	1.25
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%	3.1%	3.2%	3.4%	3.5%		Avg Ann'l Div'd Yield	2.9%

CAPITAL STRUCTURE as of 9/30/12
Total Debt $546.9 mill. Due in 5 Yrs $58.1 mill.

LT Debt $479.5 mill. LT Interest $32.0 mill.
(LT interest earned: 6.7x; total int. cov.: 6.0x)
(50% of Cap'l)

Pension Assets-12/11 $155.7 mill.
Oblig. $346.3 mill.

Pfd Stock None

Common Stock 41,905,495 shs.

as of 10/21/12

MARKET CAP: $775 million (Small Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
263.2	277.1	315.6	320.7	334.7	367.1	410.3	449.4	460.4	501.8	550	575	Revenues ($mill) E	675
19.1	19.4	26.0	27.2	25.6	31.2	39.8	40.6	37.7	36.1	41.0	45.0	Net Profit ($mill)	62.0
39.7%	39.9%	39.6%	42.4%	37.4%	39.9%	37.7%	40.3%	39.5%	40.5%	41.0%	40.5%	Income Tax Rate	40.0%
--	10.3%	3.2%	3.3%	10.6%	8.3%	8.6%	7.6%	4.2%	5.0%	5.0%	5.0%	AFUDC % to Net Profit	10.0%
55.3%	50.2%	48.6%	48.3%	43.5%	42.9%	41.6%	47.1%	52.4%	51.7%	51.0%	51.0%	Long-Term Debt Ratio	50.0%
44.0%	49.1%	50.8%	51.1%	55.9%	56.6%	58.4%	52.9%	47.6%	48.3%	49.0%	49.0%	Common Equity Ratio	50.0%
453.1	498.4	565.9	568.1	670.1	674.9	690.4	794.9	914.7	931.5	980	1040	Total Capital ($mill)	1200
697.0	759.5	800.3	862.7	941.5	1010.2	1112.4	1198.1	1294.3	1381.1	1455	1525	Net Plant ($mill)	1725
5.9%	5.6%	6.1%	6.3%	5.2%	5.9%	7.1%	6.5%	5.5%	5.5%	6.0%	6.0%	Return on Total Cap'l	7.0%
9.4%	7.8%	8.9%	9.3%	6.8%	8.1%	9.9%	9.6%	8.6%	8.0%	8.5%	9.0%	Return on Shr. Equity	10.5%
9.5%	7.9%	9.0%	9.3%	6.8%	8.1%	9.9%	9.6%	8.6%	8.0%	8.5%	9.0%	Return on Com Equity	10.5%
1.0%	.7%	2.1%	2.1%	1.0%	1.8%	3.8%	3.8%	3.0%	2.3%	3.0%	3.5%	Retained to Com Eq	4.5%
90%	91%	77%	78%	86%	77%	61%	60%	66%	71%	65%	63%	All Div'ds to Net Prof	55%

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	42.3	27.2	17.0
Other	83.9	86.7	133.1
Current Assets	126.2	113.9	150.1
Accts Payable	39.5	48.9	58.8
Debt Due	26.1	53.7	67.4
Other	41.7	49.3	64.0
Current Liab.	107.3	151.9	190.2
Fix. Chg. Cov.	304%	278%	285%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	3.5%	6.0%	4.0%
"Cash Flow"	4.5%	6.5%	5.0%
Earnings	4.0%	5.0%	6.0%
Dividends	1.0%	1.0%	3.0%
Book Value	5.0%	5.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.)E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	86.6	116.7	139.2	106.9	449.4
2010	90.3	118.3	146.3	105.5	460.4
2011	98.1	131.4	169.3	103.0	501.8
2012	116.7	143.6	178.1	111.6	550
2013	120	150	187	118	575

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.06	.29	.47	.16	.98
2010	.05	.25	.49	.12	.91
2011	.03	.29	.50	.04	.86
2012	.03	.31	.56	.07	.97
2013	.04	.33	.58	.10	1.05

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.148	.148	.148	.148	.59
2010	.149	.149	.149	.149	.60
2011	.154	.154	.154	.154	.62
2012	.1575	.1575	.1575	.1575	.63
2013					

BUSINESS: California Water Service Group provides regulated and nonregulated water service to roughly 471,900 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, '11: residential, 73%; business, 18%; public authorities, 5%; industrial, 4%. '11 reported depreciation rate: 2.7%. Has roughly 1,132 employees. President, Chairman, and CEO: Peter C. Nelson (4/11 Proxy). Inc.: Delaware. Address: 1720 North First Street, San Jose, California 95112-4598. Telephone: 408-367-8200. Internet: www.calwatergroup.com.

We suspect that earnings power is drying up at California Water Service Group. The water utility managed to post better-than-expected growth in the September period, thanks to decent top-line growth and management's ability to keep costs in check. However, it is highly unlikely that operating costs are not already on the rise. Most of the company's water-systems and pipelines are old and in need of significant repair, or complete overhauls. Thus, infrastructure repair and maintenance costs are expected be problematic, pinching margins for the foreseeable future. Although fourth-quarter results may look favorable at first, it is important to remember that the prior year's figures were historically weak.

The company's finances are a big concern going forward. Although regulatory backing has been much improved in recent years, and is expected to remain business friendly, California Water will need to shoulder a fair share of the load. That said, it is not financially capable of doing so on its own. The cash coffers are relatively bare, and cash flow generation is not likely to be sufficient enough to cover the outlays we envision over the next few years. The company will have to continue to look to outsiders to provide financing, but the necessary stock and debt offerings will also dilute gains. As a result, we look for minimal annual share-net growth this year and henceforth.

This issue is not for growth-minded investors. It is likely to provide below average annual price returns out to mid-decade, due to the increasing costs of doing business that face the industry.

We warn income-oriented parties to be cautious here, too. Although CWT's yield is tops in the Water Utilities space, the company also has the highest payout ratio in the group. This is a concern given the capital restrictions we anticipate in the years ahead and the company's weak balance sheet. We would not be surprised if the current yield slides a bit, especially if the industry landscape takes a turn for the worse and management is forced to take action. Either way, investors with a bent for income have better, more sustainable, options to choose from elsewhere.

Andre J. Costanza *January 18, 2013*

(A) Basic EPS. Excl. nonrecurring gain (loss): '00, (4¢); '01, 2¢; '02, 4¢; '11, 4¢. Next earnings report due mid-February.
(B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.
(C) Incl. deferred charges. In '11: $2.2 mill., $0.05/sh.
(D) In millions, adjusted for splits.
(E) Excludes non-reg. rev.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	90

MIDDLESEX WATER NDQ-MSEX

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
19.19	19.0	(Trailing: 22.8 / Median: 22.0)	1.20	3.9%	VALUE LINE

TIMELINESS **1** Raised 12/28/12
SAFETY **2** New 10/21/11
TECHNICAL **3** Raised 6/29/12
BETA .70 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	18.7	20.0	21.2	21.8	23.5	20.5	20.2	19.8	17.9	19.3	19.4	19.6
Low:	14.7	13.7	15.8	16.7	17.1	16.5	16.9	12.0	11.6	14.7	16.5	17.5

Target Price Range 2015 | 2016 | 2017

2015-17 PROJECTIONS

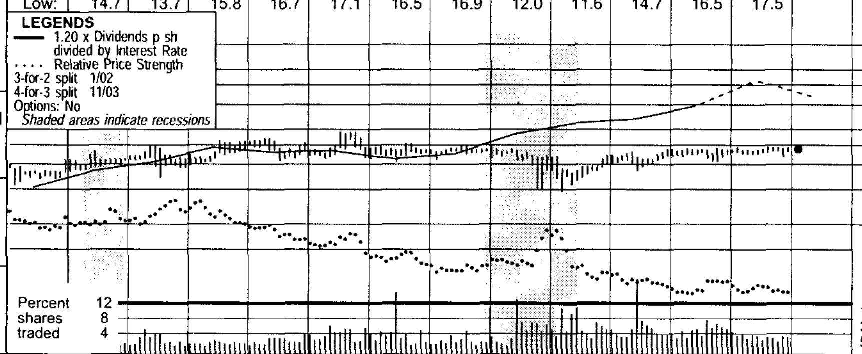
	Price	Gain	Ann'l Total Return
High	25	(+30%)	10%
Low	18	(-5%)	3%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	1	1	1	1	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	1	0	1	0	0	0

Institutional Decisions

	1Q2012	2Q2012	3Q2012
to Buy	29	32	37
to Sell	31	30	22
Hld's(000)	6511	6653	6713



% TOT. RETURN 12/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.1	17.4
3 yr.	25.3	40.1
5 yr.	27.0	40.9

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
4.52	4.72	4.39	5.35	5.39	5.87	5.98	6.12	6.25	6.44	6.16	6.50	6.79	6.75	6.60	6.50	6.90	7.10	Revenues per sh	8.40
.94	1.02	1.02	1.19	.99	1.18	1.20	1.15	1.28	1.33	1.33	1.49	1.53	1.40	1.55	1.52	1.50	1.75	"Cash Flow" per sh	2.20
.60	.67	.71	.76	.51	.66	.73	.61	.73	.71	.82	.87	.89	.72	.96	.84	.90	1.00	Earnings per sh A	1.25
.55	.57	.58	.60	.61	.62	.63	.65	.66	.67	.68	.69	.70	.71	.72	.73	.74	.75	Div'd Decl'd per sh B■	.80
.73	1.20	2.68	2.33	1.32	1.25	1.59	1.87	2.54	2.18	2.31	1.66	2.12	1.49	1.90	1.50	1.90	2.15	Cap'l Spending per sh	2.60
5.85	6.00	6.80	6.95	6.98	7.11	7.39	7.60	8.02	8.26	9.52	10.05	10.03	10.33	11.13	11.27	11.80	12.55	Book Value per sh	13.60
8.41	8.54	9.82	10.00	10.11	10.17	10.36	10.48	11.36	11.58	13.17	13.25	13.40	13.52	15.57	15.70	16.00	16.25	Common Shs Outst'g C	17.25
14.4	13.4	15.2	17.6	28.7	24.6	23.5	30.0	26.4	27.4	22.7	21.6	19.8	21.0	17.8	21.9	20.8		Avg Ann'l P/E Ratio	17.0
.90	.77	.79	1.00	1.87	1.26	1.28	1.71	1.39	1.46	1.23	1.15	1.19	1.40	1.13	1.32	1.31		Relative P/E Ratio	1.15
6.4%	6.3%	5.4%	4.4%	4.2%	3.8%	3.7%	3.5%	3.4%	3.5%	3.7%	3.7%	4.0%	4.7%	4.2%	4.2%	4.8%		Avg Ann'l Div'd Yield	3.8%

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
61.9	64.1	71.0	74.6	81.1	86.1	91.0	91.2	102.7	102.1	110	115	Revenues ($mill)	145
7.8	6.6	8.4	8.5	10.0	11.8	12.2	10.0	14.3	13.5	14.0	16.0	Net Profit ($mill)	21.5
33.3%	32.8%	31.1%	27.6%	33.4%	32.6%	33.2%	34.1%	32.1%	32.5%	32.0%	32.0%	Income Tax Rate	32.0%
--	--	--	--	--	--	--	--	6.8%	7.5%	7.5%	7.5%	AFUDC % to Net Profit	7.0%
52.1%	53.8%	53.8%	55.3%	49.5%	49.0%	45.6%	46.6%	43.1%	43.0%	42.0%	41.0%	Long-Term Debt Ratio	39.0%
45.5%	44.0%	42.5%	41.3%	47.5%	49.6%	51.8%	52.1%	55.8%	57.0%	58.0%	59.0%	Common Equity Ratio	61.0%
168.0	181.1	214.5	231.7	264.0	268.8	259.4	267.9	310.5	309.1	325	345	Total Capital ($mill)	385
211.4	230.9	262.9	288.0	317.1	333.9	366.3	376.5	405.9	422.2	440	455	Net Plant ($mill)	500
6.0%	5.0%	5.1%	5.0%	5.1%	5.6%	5.8%	5.0%	5.7%	5.3%	4.5%	4.5%	Return on Total Cap'l	5.5%
9.6%	7.9%	8.5%	8.2%	7.5%	8.6%	8.6%	7.0%	8.1%	7.5%	7.5%	8.0%	Return on Shr. Equity	9.0%
9.8%	8.0%	9.0%	8.6%	7.8%	8.7%	8.9%	7.0%	8.2%	7.6%	7.5%	8.0%	Return on Com Equity	9.0%
1.3%	NMF	.9%	.6%	1.3%	1.8%	2.0%	.1%	2.1%	1.1%	1.0%	2.0%	Retained to Com Eq	3.0%
87%	106%	90%	94%	84%	79%	78%	98%	75%	85%	85%	76%	All Div'ds to Net Prof	64%

CAPITAL STRUCTURE as of 9/30/12
Total Debt $137.5 mill. Due in 5 Yrs $25.0 mill.
LT Debt $132.4 mill. LT Interest $6.0 mill.
(LT interest coverage: 5.0x)
(42% of Cap'l)

Pension Assets-12/11 $32.2 mill.
Oblig. $56.2 mill.
Pfd Stock $3.4 mill. Pfd Div'd: $.2 mill.

Common Stock 15,754,856 shs.
as of 10/26/12

MARKET CAP: $300 million (Small Cap)

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	2.5	3.1	1.8
Other	20.3	19.8	23.9
Current Assets	22.8	22.9	25.7
Accts Payable	6.4	5.7	4.2
Debt Due	4.4	4.6	5.1
Other	29.9	36.4	40.6
Current Liab.	40.7	46.7	49.9
Fix. Chg. Cov.	400%	380%	300%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	3.0%	1.5%	4.0%
"Cash Flow"	3.5%	3.5%	7.0%
Earnings	2.5%	4.5%	7.0%
Dividends	2.0%	1.5%	1.5%
Book Value	4.5%	5.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	20.6	23.1	25.5	22.0	91.2
2010	21.6	26.5	29.6	25.0	102.7
2011	24.0	26.1	28.7	23.3	102.1
2012	23.5	27.4	32.3	26.8	110
2013	28.0	28.0	32.0	27.0	115

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.10	.21	.29	.12	.72
2010	.11	.31	.37	.17	.96
2011	.17	.23	.32	.12	.84
2012	.11	.23	.38	.18	.90
2013	.20	.25	.35	.20	1.00

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.178	.178	.178	.180	.71
2010	.180	.180	.180	.183	.72
2011	.183	.183	.183	.185	.73
2012	.185	.185	.185	.1875	.74
2013					

BUSINESS: Middlesex Water Company engages in the ownership and operation of regulated water utility systems in New Jersey, Delaware, and Pennsylvania. It also operates water and wastewater systems under contract on behalf of municipal and private clients in NJ and DE. Its Middlesex System provides water services to 60,000 retail customers, primarily in Middlesex County, New Jersey. in 2011, the Middlesex System accounted for 64% of total revenues. At 12/31/11, the company had 289 employees. Incorporated: NJ. President, CEO, and Chairman: Dennis W. Doll. Officers/directors own 3.39% of the common stock; BlackRock, 6.2%; The Vanguard Group, 5.4% (4/12 proxy). Address: 1500 Ronson Road, Iselin, NJ 08830. Tel.: 732-634-1500. Internet: www.middlesexwater.com.

Middlesex Water should be able to grow the bottom line in 2013. In fact, we believe share earnings could likely rise 10%-12%. We think recent rate increases, debt refinancing, and a recovering New Jersey housing market will drive decent share-net gains. The most notable rate increase in 2012 was an $8.1 million increase for New Jersey customers in its Middlesex system. (The company had requested a rate increase of $11.3 million per year.) Additionally, the Tidewater business in Delaware saw a $3.9 million upgrade to its base water rates.

Hurricane Sandy and a lackluster job market are a concern. The company mostly escaped the devastation of the hurricane. The one notable disturbance was the loss of power at an intake station in New Brunswick, New Jersey. However, the storm's impact will likely hurt an already weak job market in the state. MSEX continues to face reductions in demand from a number of its largest commercial and industrial customers. However, we do expect the housing market to boost customers and water usage in the coming years.

Capital investment will likely help longer-term growth. The company expects to invest $34 million over the next two years. The vast majority of these investments are targeted toward its Distribution systems. We believe the focus on water distribution infrastructure is crucial to help offset the weakening demand from commercial and industrial customers.

The company has increased its quarterly dividend. The 1.3% hike was expected when considering MSEX's payout history.

We have adjusted our top- and bottom-line estimates for 2013. We have slightly raised our revenue and share-net projections to $115 million and $1.00, respectively.

The issue has a Timeliness rank of 1 (Highest). The income-minded investor may also find these shares appealing, as the dividend yield is above the *Value Line* median and most of its peers. However, a rich valuation and the stock's below-average 3- to 5-year capital appreciation potential suggest that long-term investors should stay on the sidelines.

Michael Collins *January 18, 2013*

(A) Diluted earnings. Next earnings report due early March.
(B) Dividends historically paid in mid-Feb., May, Aug., and November.■ Div'd reinvestment plan available.
(C) In millions, adjusted for splits.
(D) Intangible assets in 2011: $8.2 million, $0.55 a share.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	85

SJW CORP. NYSE-SJW

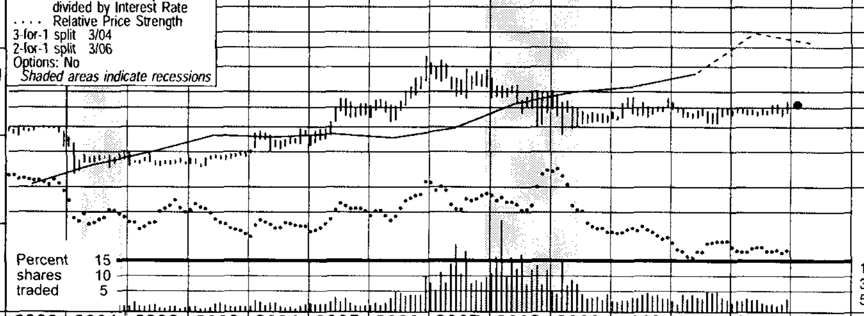
RECENT PRICE	25.97	P/E RATIO	22.8 (Trailing: 21.3 / Median: 23.0)	RELATIVE P/E RATIO	1.44	DIV'D YLD	2.7%	VALUE LINE

TIMELINESS 2 Raised 1/11/13
SAFETY 3 New 4/22/11
TECHNICAL 3 Lowered 12/28/12
BETA .85 (1.00 = Market)

High:	17.8	15.1	15.0	19.6	27.8	45.3	43.0	35.1	30.4	28.2	26.8	26.9
Low:	11.6	12.7	12.6	14.6	16.1	21.2	27.7	20.0	18.2	21.6	20.9	22.6

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-1 split 3/04
2-for-1 split 3/06
Options: No
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+75%)	17%
Low	30	(+15%)	6%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	1	0	1	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2012	2Q2012	3Q2012
to Buy	34	34	31
to Sell	22	31	31
Hld's(000)	9012	8955	8844

Percent shares traded 15 10 5

% TOT. RETURN 12/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.9	17.4
3 yr.	28.6	40.1
5 yr.	-11.8	40.9

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
5.39	5.79	5.58	6.40	6.74	7.45	7.97	8.20	9.14	9.86	10.35	11.25	12.12	11.68	11.62	12.86	14.15	13.75	Revenues per sh	15.00
1.43	1.27	1.26	1.43	1.23	1.49	1.55	1.75	1.89	2.21	2.38	2.30	2.44	2.21	2.38	2.80	2.85	2.95	Cash Flow" per sh	3.20
.96	.80	.76	.87	.58	.77	.78	.91	.87	1.12	1.19	1.04	1.08	.81	.84	1.11	1.05	1.20	Earnings per sh A	1.45
.37	.38	.39	.40	.41	.43	.46	.49	.51	.53	.57	.61	.65	.66	.68	.69	.71	.73	Div'd Decl'd per sh B■	.80
1.06	1.27	1.81	1.77	1.89	2.63	2.06	3.41	2.31	2.83	3.87	6.62	3.79	3.17	5.65	3.75	4.80	4.75	Cap'l Spending per sh	4.10
6.31	7.02	7.53	7.88	7.90	8.17	8.40	9.11	10.11	10.72	12.48	12.90	13.99	13.66	13.75	14.20	15.45	16.25	Book Value per sh	17.95
19.02	19.02	19.01	18.27	18.27	18.27	18.27	18.27	18.27	18.27	18.28	18.36	18.18	18.50	18.55	18.59	18.75	20.00	Common Shs Outst'g C	22.00
6.8	11.2	13.1	15.5	33.1	18.5	17.3	15.4	19.6	19.7	23.5	33.4	26.2	28.7	29.1	21.2	22.9		Avg Ann'l P/E Ratio	25.0
.43	.65	.68	.88	2.15	.95	.94	.88	1.04	1.05	1.27	1.77	1.58	1.91	1.85	1.34	1.44		Relative P/E Ratio	1.65
5.7%	4.3%	3.9%	3.0%	2.1%	3.0%	3.4%	3.5%	3.0%	2.4%	2.0%	1.7%	2.3%	2.8%	2.8%	2.9%	3.0%		Avg Ann'l Div'd Yield	2.1%

CAPITAL STRUCTURE as of 9/30/12
Total Debt $341.2 mill. Due in 5 Yrs $5.2 mill.
LT Debt $335.8 mill. LT Interest $18.7 mill.
(Total interest coverage: 4.6x) (55% of Cap'l)

Leases, Uncapitalized: Annual rentals $4.5 mill.

Pension Assets-12/11 $62.8 mill. **Oblig.** $123.9 mill.

Pfd Stock None.

Common Stock 18,653,633 shs. as of 10/19/12

MARKET CAP: $475 million (Small Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
145.7	149.7	166.9	180.1	189.2	206.6	220.3	216.1	215.6	239.0	265	275	Revenues ($mill)	330
14.2	16.7	16.0	20.7	22.2	19.3	20.2	15.2	15.8	20.9	20.5	24.0	Net Profit ($mill)	31.0
40.4%	36.2%	42.1%	41.6%	40.8%	39.4%	39.5%	40.4%	38.8%	41.1%	40.5%	40.0%	Income Tax Rate	40.0%
4.2%	1.6%	2.1%	1.6%	2.1%	2.7%	2.3%	2.0%	2.0%	3.0%	5.0%	5.0%	AFUDC % to Net Profit	5.0%
41.7%	45.6%	43.7%	42.6%	41.8%	47.7%	46.0%	49.4%	53.7%	56.6%	55.5%	53.5%	Long-Term Debt Ratio	52.0%
58.3%	54.4%	56.3%	57.4%	58.2%	52.3%	54.0%	50.6%	46.3%	43.4%	44.5%	46.5%	Common Equity Ratio	48.0%
263.5	306.0	328.3	341.2	391.8	453.2	470.9	499.6	550.7	607.8	650	700	Total Capital ($mill)	820
390.8	428.5	456.8	484.8	541.7	645.5	684.2	718.5	785.5	756.2	815	875	Net Plant ($mill)	1050
6.9%	6.9%	6.5%	7.6%	7.0%	5.7%	5.8%	4.4%	4.3%	5.0%	4.5%	5.0%	Return on Total Cap'l	5.0%
9.3%	10.0%	8.7%	10.6%	9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	7.0%	7.5%	Return on Shr. Equity	7.0%
9.3%	10.0%	8.7%	10.6%	9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	7.0%	7.5%	Return on Com Equity	7.0%
3.8%	4.7%	3.6%	5.6%	5.2%	3.5%	3.3%	1.2%	1.2%	3.1%	2.5%	3.0%	Retained to Com Eq	3.5%
59%	53%	58%	47%	46%	57%	59%	80%	80%	61%	64%	61%	All Div'ds to Net Prof	57%

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	1.7	26.7	6.7
Other	36.3	42.2	55.4
Current Assets	38.0	68.9	62.1
Accts Payable	5.5	7.4	17.6
Debt Due	5.1	.8	5.4
Other	18.6	20.1	27.9
Current Liab.	29.2	28.3	50.9
Fix. Chg. Cov.	262%	276%	250%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.0%	4.5%	3.5%
"Cash Flow"	6.0%	2.5%	4.5%
Earnings	2.0%	-3.0%	8.0%
Dividends	5.0%	5.0%	3.0%
Book Value	5.5%	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	40.0	58.2	69.3	48.6	216.1
2010	40.4	54.1	70.3	50.8	215.6
2011	43.7	59.0	73.9	62.4	239.0
2012	51.2	65.6	82.4	65.8	265
2013	54.0	69.0	84.0	68.0	275

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.01	.23	.43	.14	.81
2010	.05	.24	.44	.11	.84
2011	.03	.29	.44	.35	1.11
2012	.06	.28	.53	.18	1.05
2013	.10	.33	.55	.22	1.20

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.165	.165	.165	.165	.66
2010	.17	.17	.17	.17	.68
2011	.173	.173	.173	.173	.69
2012	.1775	.1775	.1775	.1775	.71
2013					

BUSINESS: SJW Corporation engages in the production, purchase, storage, purification, distribution, and retail sale of water. It provides water service to approximately 226,000 connections that serve a population of approximately one million people in the San Jose area and 8,700 connections that serve approximately 36,000 residents in a service area in the region between San Antonio and Austin, Texas. The company offers nonregulated water-related services, including water system operations, cash remittances, and maintenance contract services. SJW also owns and operates commercial real estate investments. Has 375 employees. Chairman: Charles J. Toeniskoetter. Inc.: CA. Address: 110 W. Taylor Street, San Jose, CA 95110. Tel.: (408) 279-7800. Int:www.sjwater.com.

SJW will probably report a steep earnings decline in the fourth quarter. The water utility's 2011 December-period results benefited greatly from the recognition of a Mandatory Conservation Revenue Adjustment Account (MCRAM), the likes of which are not expected to have been recovered again in 2012. We suspect that share net fell nearly 50% absent this $0.18-per-share contribution. Meanwhile, rising operating costs are expected to have offset any top-line momentum gained from good weather.

Growth is likely to get a boost in 2013. We expect a favorable ruling to be handed down shortly on the company's 2013-2015 general rate case. If we are correct, the contribution will result in double-digit earnings growth.

That said, the momentum is expected to be short-lived. Infrastructure improvements are expected to total hundreds of millions of dollars over the next few years. SJW, however, is cash-poor and has an already highly leveraged balance sheet. Improved regulatory backing will help, but cash flows from operations are likely to pale in comparison to the company's obligations. It will have to issue more stock and/or debt in order to make the changes, but such financing will dilute gains for the foreseeable future. As a result, we look for earnings growth to fall off considerably in 2014, and to remain muted thereafter.

This issue is favorably ranked for Timeliness as a result of its recent earnings power. Still, potential investors are advised to be careful. SJW does not stand out for price appreciation potential over the coming 3 to 5 years because of the company's financial limitations. Indeed, the financing needed to make infrastructure improvements will erase a fair share of the regulatory benefits we envision. True, the dividend is above the *Value Line* average, but it is far less impressive when compared to other utilities. Thus, there are much better choices for investors seeking an income producer. Meanwhile, we caution that annual dividend increases may slow if operating conditions worsen or regulatory backing sours. Nevertheless, SJW is one of the better total return vehicles offered in this space for those looking to gain exposure to water utilities.

Andre J. Costanza *January 18, 2013*

(A) Diluted earnings. Excludes nonrecurring losses : '03, $1.97; '04, $3.78; '05, $1.09; '06, $16.36; '08, $1.22; '10, 46¢. Next earnings report due late February. Quarterly egs. 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 stock splits.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	60
Earnings Predictability	80

AQUA AMERICA NYSE-WTR

RECENT PRICE **26.01** | P/E RATIO **24.5** (Trailing: 23.4 / Median: 25.0) | RELATIVE P/E RATIO **1.55** | DIV'D YLD **2.7%** | VALUE LINE

TIMELINESS **2** Raised 10/5/12
SAFETY **2** Raised 4/20/12
TECHNICAL **3** Lowered 11/16/12
BETA .60 (1.00 = Market)

High:	14.8	15.0	16.8	18.5	29.2	29.8	26.6	22.0	21.5	23.0	23.8	26.9
Low:	9.4	9.6	11.8	14.2	17.5	20.1	18.9	12.2	15.4	16.5	19.3	21.1

2015-17 PROJECTIONS

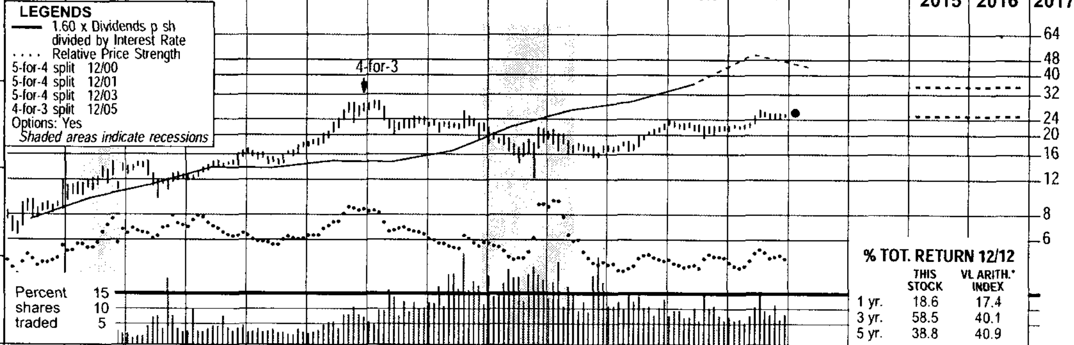
	Price	Gain	Ann'l Total Return
High	35	(+35%)	*10%*
Low	25	(-5%)	*2%*

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	2	0	1	0	0	0
to Sell	0	0	0	3	1	0	0	0	0

Institutional Decisions

	1Q2012	2Q2012	3Q2012
to Buy	114	112	117
to Sell	104	108	108
Hld's(000)	57767	60392	64465



% TOT. RETURN 12/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.6	17.4
3 yr.	58.5	40.1
5 yr.	38.8	40.9

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
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	4.91	5.26	5.13	*5.55*	*5.80*	Revenues per sh	*6.60*
.50	.56	.61	.72	.76	.86	.94	.96	1.09	1.21	1.26	1.37	1.42	1.61	1.78	1.84	*1.90*	*2.05*	"Cash Flow" per sh	*2.30*
.30	.34	.40	.42	.47	.51	.54	.57	.64	.71	.70	.71	.73	.77	.90	1.03	*1.05*	*1.15*	Earnings per sh A	*1.35*
.23	.24	.26	.27	.28	.30	.32	.35	.37	.40	.44	.48	.51	.55	.59	.62	.67	*.71*	Div'd Decl'd per sh B■	*.80*
.48	.58	.82	.90	1.16	1.09	1.20	1.32	1.54	1.84	2.05	1.79	1.98	2.08	2.37	2.38	*2.40*	*2.65*	Cap'l Spending per sh	*2.70*
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	8.12	8.51	9.01	*9.25*	*9.75*	Book Value per sh	*10.85*
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	136.49	137.97	138.87	*140.90*	*141.90*	Common Shs Outst'g C	*143.90*
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	23.1	21.1	21.1	*22.8*		Avg Ann'l P/E Ratio	*21.0*
.98	1.03	1.17	1.21	1.18	1.21	1.29	1.40	1.33	1.69	1.87	1.70	1.50	1.54	1.34	1.36	*1.43*		Relative P/E Ratio	*1.40*
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%	3.1%	3.1%	3.1%	2.8%		Avg Ann'l Div'd Yield	*2.8%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $1658.4 mill. **Due in 5 Yrs** $300 mill.
LT Debt $1519.7 mill. **LT Interest** $65.0 mill.
(LT interest earned: 5.3x; total interest coverage: 4.4x) (54% of Cap'l)

Pension Assets-12/11 $148.9 mill. **Oblig.** $237.1 mill.

Pfd Stock None
Common Stock 139,941,476 shares as of 10/24/12
MARKET CAP: $3.6 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
322.0	367.2	442.0	496.8	533.5	602.5	627.0	670.5	726.1	712.0	*785*	*825*	Revenues ($mill)	*950*
62.7	67.3	80.0	91.2	92.0	95.0	97.9	104.4	124.0	143.1	*145*	*160*	Net Profit ($mill)	*195*
38.5%	39.3%	39.4%	38.4%	39.6%	38.9%	39.7%	39.4%	39.2%	32.9%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
--	--	--	--	--	--	--	--	2.9%	3.1%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
54.2%	51.4%	50.0%	52.0%	51.6%	55.4%	54.1%	55.6%	56.6%	53.0%	*52.0%*	*50.0%*	Long-Term Debt Ratio	*46.0%*
45.8%	48.6%	50.0%	48.0%	48.4%	44.6%	45.9%	44.4%	43.4%	47.0%	*48.0%*	*50.0%*	Common Equity Ratio	*54.0%*
1076.2	1355.7	1497.3	1690.4	1904.4	2191.4	2306.6	2495.5	2706.2	2647.3	*2715*	*2760*	Total Capital ($mill)	*2885*
1490.8	1824.3	2069.8	2280.0	2506.0	2792.8	2997.4	3227.3	3469.3	3612.9	*3785*	*3960*	Net Plant ($mill)	*4320*
7.6%	6.4%	6.7%	6.9%	6.4%	5.9%	5.7%	5.6%	5.9%	6.8%	*5.5%*	*6.0%*	Return on Total Cap'l	*4.5%*
12.7%	10.2%	10.7%	11.2%	10.0%	9.7%	9.3%	9.4%	10.6%	11.4%	*11.0%*	*11.5%*	Return on Shr. Equity	*12.5%*
12.7%	10.2%	10.7%	11.2%	10.0%	9.7%	9.3%	9.4%	10.6%	11.4%	*11.0%*	*11.5%*	Return on Com Equity	*12.5%*
5.2%	4.2%	4.6%	4.9%	3.7%	3.2%	2.8%	2.7%	3.7%	4.6%	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
59%	59%	57%	56%	63%	67%	70%	72%	65%	60%	*65%*	*63%*	All Div'ds to Net Prof	*59%*

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	5.9	8.2	6.1
Receivables	85.9	81.1	103.8
Inventory (AvgCst)	9.2	11.2	12.2
Other	44.4	220.0	108.9
Current Assets	145.4	320.5	231.0
Accts Payable	45.3	68.3	45.1
Debt Due	28.5	80.4	138.7
Other	149.9	277.0	131.3
Current Liab.	223.7	425.7	315.1
Fix. Chg. Cov.	290%	367%	328%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	8.0%	7.5%	*4.5%*
"Cash Flow"	8.5%	8.0%	*5.0%*
Earnings	6.5%	4.5%	*7.0%*
Dividends	7.5%	8.0%	*5.0%*
Book Value	9.0%	7.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	154.5	167.3	180.8	167.9	670.5
2010	160.5	178.5	207.8	179.3	726.1
2011	163.6	178.3	197.3	172.7	712.0
2012	170.2	198.2	214.6	*202*	*785*
2013	*180*	*210*	*215*	*220*	*825*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.14	.19	.25	.19	.77
2010	.16	.22	.32	.20	.90
2011	.22	.27	.30	.25	1.03
2012	.20	.30	.36	*.19*	*1.05*
2013	*.22*	*.29*	*.39*	*.25*	*1.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.135	.135	.135	.145	.55
2010	.145	.145	.145	.155	.59
2011	.155	.155	.155	.165	.63
2012	.165	.165	.165	.175	.67
2013					

BUSINESS: Aqua America, Inc. is the holding company for water and wastewater utilities that serve approximately three 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 '11: residential, 59.5%; commercial, 14.5%; industrial & other, 26.0%. Officers and directors own 1.5% of the common stock (4/12 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 will likely grow at a decent clip in 2013. Indeed, we expect the shale-water pipeline business, the retooling of its portfolio, and cost controls to drive a 9% year-over-year rise in the bottom line. Additionally, we are looking for an acceleration of infrastructure investments over the next two years. Management estimates that capital spending should increase 8%-10% from the 2012 figure. The majority of investments will be focused on pipe replacement projects to improve its distribution networks and upgrade plants. These investments are necessary, considering that the housing market appears to be rebounding. On the cost side, the construction of four solar farms and the conversion of their truck fleet to natural gas should help margins.

We have raised our 2013 share-net estimate. We have increased our 2013 top- and bottom-line estimates to $825 million and $1.15 a share, respectively.

The Marcellus water pipeline venture should boost longer-term profitability. Phase II of the project was most likely completed at the end of 2012. The pipeline has already eliminated the need for 15,000 water truck trips over the rural roads of Pennsylvania. With the recent uptick in natural gas prices, drilling activity should start picking up for oil & gas operators. WTR may also start looking to penetrate the Utica market, as well.

The company's portfolio restructuring efforts should continue into 2013. There has been no update on Aqua America's $95 million offer to sell its Florida operations to the Florida Governmental Utility Authority. The leaner portfolio plan will consolidate its operations to 8 markets, with Ohio and Texas offering the most promise, due to lighter regulations and improving demographics.

A dividend hike provides a welcoming sign. However, further increases are unlikely in the near term, as management shifts its focus on M&A and capital investments.

The stock is set to outperform the broader market averages in the near term. The issue should have some appeal to income-oriented accounts, due to its above-average dividend yield when compared to the *Value Line* median.

Michael Collins *January 18, 2013*

(A) Diluted egs. Excl. nonrec. gains (losses): '99, (11¢); '00, 2¢; '01, 2¢; '02, 5¢; '03, 4¢. Excl. gain from disc. operations: '96, 2¢. Next earnings report due late February.
(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	100
Price Growth Persistence	65
Earnings Predictability	100

ATTACHMENT B

Equities in the Natural Gas Utility Industry have been under some pressure over the past few months. This can be attributed partly to weakness in the general market. Indeed, there are worries about the possibility of the so-called fiscal cliff taking effect by the end of 2012, unless President Obama and the bitterly divided Congress act in time. (That event would be marked by an estimated $600 billion in automatic tax hikes and spending cuts.) Furthermore, there is investor uncertainty over the outcome of the sovereign debt crisis in Europe and concerns about the strength of the Chinese economy. But even under those circumstances, the equities in our Industry have tended to hold up relatively well. Indeed, their healthy levels of dividend income have provided a measure of much-needed stability.

The United States Economy

The economy perked up some in the third quarter, with Gross Domestic Product (GDP) increasing an estimated 2.7%, relative to 1.3% during the June interim and 2.0% in the first three months of 2012. Contributing factors included restocking by businesses and export growth outpacing a rise in imports. What's more, there was a turnaround in federal government expenditures, driven by higher defense outlays, as well as a strengthening housing market (reflecting a boost in residential construction).

Nevertheless, the pace of the economic recovery continues to be sluggish, attributable partially to the persistently high unemployment rate, hovering a little below 8% at present. Too, it appears that Hurricane Sandy, discussed in further detail below, will cost thousands of jobs, some of which will take some time to restore. Also, the fiscal cliff, if not resolved in time, has the potential to seriously damage the economy. Finally, the lingering European debt crisis has further complicated matters. In this difficult operating environment, customers have been focusing on energy conservation, which, of course, acts as a restraint on the revenues of the companies included in the Natural Gas Utility Industry.

Hurricane Sandy

In late October, the powerful storm ravaged the eastern coast of the United States, particularly New Jersey and New York, leaving millions of people without power. As a result, we have scaled back our fourth-quarter GDP growth target by about 0.5%, to between 1.2% and 1.5%. True, a portion of this shortfall will be made up in 2013, as rebuilding initiatives take hold, but some might never be recaptured. (Current estimates state that the total damage from the storm could be more than $50 billion.)

Natural gas distribution pipelines are located mostly underground, providing a good measure of protection against adverse weather conditions. Even so, these assets can be damaged by uprooted trees and shifted foundations. In addition, fallen tree limbs and other debris can crush gas meters and associated piping near homes and other buildings. Still, it appears that companies in the group held up reasonably well during Hurricane Sandy.

INDUSTRY TIMELINESS: 27 (of 98)

Rate Cases

Rate cases are a very important issue for natural gas utilities. Federal authorities establish wholesale service tariffs, and state regulators determine retail distribution rates. Adequate returns on common equity are necessary to keep these businesses viable. Higher rates are sought to pay for the cost of expansion, storm damage and/or to cover the expenses of maintaining reliable service. To promote good relationships with customers and regulators, managements endeavor to keep operating and service costs as low as possible. At times, however, political pressure can compel authorities to limit rates of return, to the detriment of utility companies. But mostly, regulators attempt to strike an equitable balance between the interests of shareholders and customers.

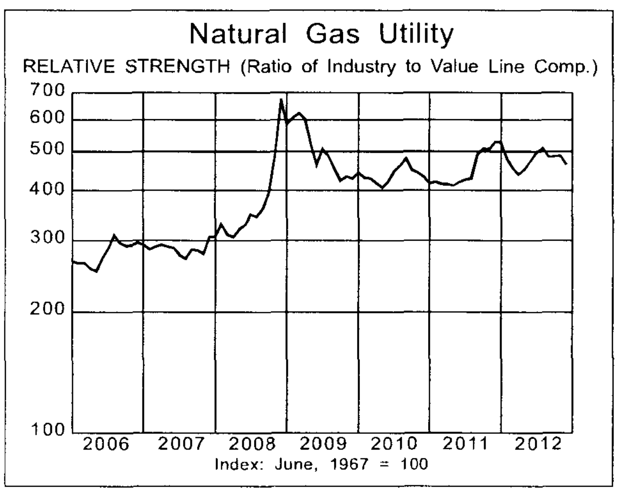
Dividends

The primary attraction of utility equities is their generous levels of dividend income. At the time of this writing, the average yield for the 11 companies in our group was around 4.0%, considerably higher than the *Value Line* median of 2.3%. Standouts include *AGL Resources*, *Northwest Natural Gas*, *Laclede Group*, and *WGL Holdings*. When the financial markets are turbulent, which seems to be more common these days, healthy dividend yields tend to act as an anchor, so to speak, in this category.

Conclusion

Stocks in the Natural Gas Utility Industry are most appropriate for income-oriented investors with a conservative bent (given that a number of these issues are ranked favorably for Safety and earn high marks for Price Stability). It should be noted, however, that companies with larger nonregulated operations may offer a higher potential for returns, though profits could be more volatile than for companies with a greater emphasis on the more stable utility segment. As always, our readers are advised to carefully examine the following reports before making a commitment.

Frederick L. Harris, III



AGL RESOURCES NYSE-GAS

RECENT PRICE 38.41 | P/E RATIO 11.0 (Trailing: 20.3 / Median: 13.0) | RELATIVE P/E RATIO 0.74 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 3 Raised 3/11/11

SAFETY 1 Raised 9/9/11

TECHNICAL 3 Lowered 11/23/12

BETA .75 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1	37.5	40.1	43.7	42.9
Low:	19.0	17.3	21.9	26.5	32.0	34.4	35.2	24.0	24.0	34.2	34.1	36.6

Target Price Range 2015 | 2016 | 2017

2015-17 PROJECTIONS

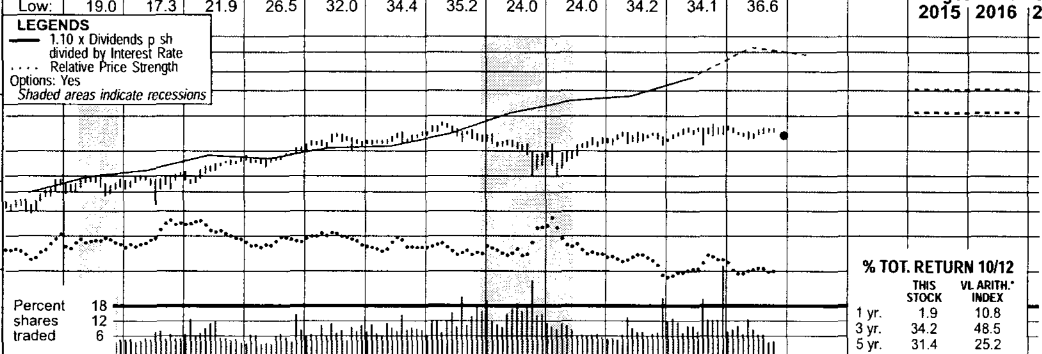
	Price	Gain	Ann'l Total Return
High	65	(+70%)	18%
Low	50	(+30%)	11%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	1	1	0	0	2	0	0	2	0
to Sell	0	1	0	0	2	0	0	2	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	258	153	136
to Sell	63	159	151
Hld's(000)	71384	71603	69954



% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.9	10.8
3 yr.	34.2	48.5
5 yr.	31.4	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
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	29.88	30.42	20.00	*34.95*	*37.15*	Revenues per sh A	*44.30*
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	4.90	5.05	3.05	*6.00*	*6.15*	"Cash Flow" per sh	*7.35*
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	2.88	3.00	2.12	*2.70*	*3.20*	Earnings per sh A B	*3.80*
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	1.90	*1.74*	*1.84*	Div'ds Decl'd per sh CF■	*1.96*
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	6.14	6.54	3.42	*4.75*	*5.15*	Cap'l Spending per sh	*6.45*
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	22.95	23.24	28.54	*30.90*	*31.65*	Book Value per sh D	*33.30*
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	77.54	78.00	117.00	*117.00*	*117.00*	Common Shs Outst'g E	*117.0*
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	11.2	12.5	12.6	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	.75	.80	.82	*Value Line*		Relative P/E Ratio	*1.00*
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%	5.4%	4.7%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/12

Total Debt $4604 mill. **Due in 5 Yrs** $100 mill.
LT Debt $3330 mill. **LT Interest** $200 mill.
(Total interest coverage: 6.5x)

Leases, Uncapitalized Annual rentals $95.0 mill.
Pension Assets-12/11 $754.0 mill.
Oblig. $968.0 mill.

Pfd Stock None

Common Stock 117,782,207 shs.
as of 10/23/12

MARKET CAP: $4.5 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	2317.0	2373.0	2338.0	*4100*	*4350*	Revenues ($mill) A	*5180*
103.0	132.4	153.0	193.0	212.0	211.0	207.6	222.0	234.0	172.0	*315*	*375*	Net Profit ($mill)	*445*
36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	40.5%	35.2%	35.9%	40.2%	*35.5%*	*32.0%*	Income Tax Rate	*32.0%*
11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	9.6%	9.9%	7.4%	*7.7%*	*8.6%*	Net Profit Margin	*8.6%*
58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	52.6%	48.0%	52.0%	*52.0%*	*52.5%*	Long-Term Debt Ratio	*56.0%*
41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	47.4%	52.0%	48.0%	*48.0%*	*47.5%*	Common Equity Ratio	*44.0%*
1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	3754.0	3486.0	8238.0	*7535*	*7855*	Total Capital ($mill)	*8840*
2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	4146.0	4405.0	7900.0	*8375*	*8875*	Net Plant ($mill)	*10570*
8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	7.4%	6.9%	7.6%	3.0%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	*9.0%*	*10.0%*	Return on Shr. Equity	*11.5%*
14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	*3.0%*	*4.5%*	Return on Com Equity	*5.5%*
7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	5.1%	5.3%	5.6%	.7%	*3.0%*	*4.0%*	Retained to Com Eq	*6.5%*
52%	53%	49%	52%	52%	58%	60%	57%	57%	86%	*65%*	*58%*	All Div'ds to Net Prof	*52%*

CURRENT POSITION ($MILL.)

	2010	2011	9/30/12
Cash Assets	24	69	91
Other	2138	2677	2044
Current Assets	2162	2746	2135
Accts Payable	184	294	292
Debt Due	1032	1338	1274
Other	1212	1452	1198
Current Liab.	2428	3984	2764
Fix. Chg. Cov.	501%	325%	385%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.0%	5.5%	*9.0%*
"Cash Flow"	6.5%	6.0%	*9.0%*
Earnings	9.0%	4.5%	*6.0%*
Dividends	5.0%	7.5%	*1.5%*
Book Value	7.0%	5.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	995	377	307	638	2317
2010	1003	359	346	665	2373
2011	878	375	295	790	2338
2012	1404	686	614	*1396*	*4100*
2013	*1780*	*690*	*585*	*1295*	*4350*

Cal-endar	EARNINGS PER SHARE A B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.55	.26	.16	.91	2.88
2010	1.73	.17	.29	.81	3.00
2011	1.59	.23	d.04	.37	2.12
2012	1.12	.28	.08	*1.22*	*2.70*
2013	*1.95*	*.25*	*.15*	*.85*	*3.20*

Cal-endar	QUARTERLY DIVIDENDS PAID CF■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.42	.42	.42	.42	1.68
2009	.43	.43	.43	.43	1.72
2010	.44	.44	.44	.44	1.76
2011	.45	.45	.45	.55	1.90
2012	.36	.46	.46	.46	

BUSINESS: AGL Resources Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, and Virginia Natural Gas. Acquired Nicor in 2011. The utilities have more than 2.3 million customers in Georgia, Virginia, Tennessee, New Jersey, and Florida. Engaged in nonregulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. BlackRock Inc. owns 6.8% of common stock; off./dir., less than 1.0% (3/12 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.

AGL Resources reported mixed results in the third quarter. Revenues increased to $614 million (up 108% year over year); earnings were $0.08 a share compared to last year's $0.04-a-share loss. Still, earnings were lower than expected, and were hurt by a $16 million hedging loss. Revenues are expected to grow strongly in the fourth quarter, aided by the Nicor acquisition. Revenues and earnings, however, could be adversely affected if a warmer-than-usual winter occurs.

Hurricane Sandy may have a small negative effect on profits in the fourth quarter. AGL's subsidiary, Elizabethtown Gas, is located in central New Jersey, which took the brunt of the storm. Damages and losses due to wind and flooding were incurred, and revenue was lost due to customers losing power. The Virginia Natural Gas Company, another subsidiary that was projected to be in the storm's path, remained largely unaffected. The damage from the storm could have lingering effects on the top and bottom line in the fourth quarter.

AGL's subsidiaries continue to strive for growth. Atlanta Gas Light Co. recently inked an agreement that permits it to install five new compressed natural gas fueling stations throughout Georgia. The Nicor acquisition continues to be integrated, and costs savings are slowly being realized. Fourth-quarter earnings should be helped by these cost-savings initiatives.

We have lowered our Target Price Range from $55-$70 to $50-$65. Pressures from high supply in the natural gas market will hurt distributors and temper revenue and earnings gains, countering growth in new customers and projects.

This issue has retreated some since last report, increasing the dividend yield to 4.8% for new investors. We expect the payout to expand in 2013, as earnings continue to grow.

These shares' Timeliness rank is 3 (Average). AGL Resources will likely perform in line with the broader market over the next six to 12 months. However, those who seek dividend income should consider this issue due to its high yields, the likelihood of increased payouts and the Highest Safety rank of 1.

John E. Seibert III *December 7, 2012*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses):'99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late January.
(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2011: $1918 million, $16.40/share.
(E) In millions. (F) Excluding special dividends from the Nicor merger.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	75

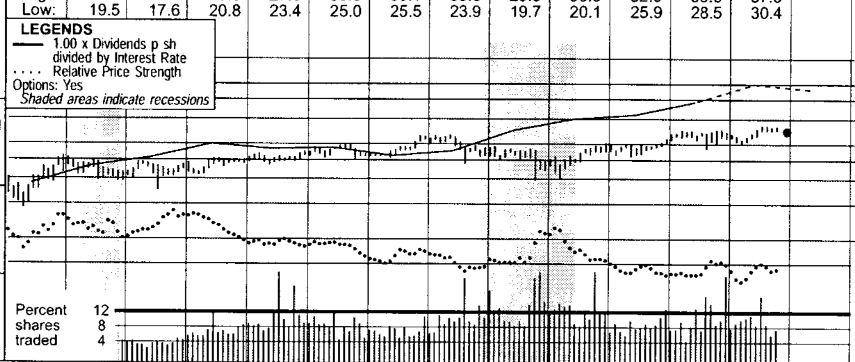
ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
34.78	15.0 (Trailing: 15.1 / Median: 14.0)	1.01	4.1%	VALUE LINE

TIMELINESS **2** Raised 8/17/12
SAFETY **2** Raised 12/16/05
TECHNICAL **3** Lowered 11/23/12
BETA .70 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3	30.3	32.0	35.6	37.3
Low:	19.5	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.1	25.9	28.5	30.4

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+15%)	7%
Low	30	(-15%)	1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	2	0	0	1	0
to Sell	0	0	1	0	0	1	0	2	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	132	127	112
to Sell	103	117	131
Hld's(000)	48646	50572	51653

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.2	10.8
3 yr.	47.3	48.5
5 yr.	61.9	25.2

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.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.82	54.39	46.50	61.75	75.27	66.03	79.52	53.69	53.12	48.15	38.20	41.75	Revenues per sh A	63.10
3.39	3.23	2.91	3.90	4.26	4.14	4.19	4.29	4.64	4.72	4.75	5.10	"Cash Flow" per sh	5.65
1.45	1.71	1.58	1.72	2.00	1.94	2.00	1.97	2.16	2.26	2.10	2.35	Earnings per sh A B	2.70
1.18	1.20	1.22	1.24	1.26	1.28	1.30	1.32	1.34	1.36	1.38	1.40	Div'ds Decl'd per sh C ■	1.48
3.17	3.10	3.03	4.14	5.20	4.39	5.20	5.51	6.02	6.90	8.15	8.50	Cap'l Spending per sh	8.80
13.75	16.66	18.05	19.90	20.16	22.01	22.60	23.52	24.16	24.98	26.20	29.00	Book Value per sh	34.65
41.68	51.48	62.80	80.54	81.74	89.33	90.81	92.55	90.16	90.30	90.00	91.00	Common Shs Outst'g D	103.00
15.2	13.4	15.9	16.1	13.5	15.9	13.6	12.5	13.2	14.4	15.9		Avg Ann'l P/E Ratio	13.0
.83	.76	.84	.86	.73	.84	.82	.83	.84	.90	1.01		Relative P/E Ratio	.85
5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%		Avg Ann'l Div'd Yield	4.2%
950.8	2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	4969.1	4789.7	4347.6	3438.5	3800	Revenues ($mill) A	6500
59.7	79.5	86.2	135.8	162.3	170.5	180.3	179.7	201.2	199.3	192.2	215	Net Profit ($mill)	280
37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	34.4%	38.5%	36.4%	33.8%	35.0%	Income Tax Rate	38.5%
6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	3.6%	4.2%	4.6%	5.6%	5.7%	Net Profit Margin	4.3%
53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	49.9%	45.4%	49.4%	45.5%	45.0%	Long-Term Debt Ratio	49.0%
46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	50.1%	54.6%	50.6%	54.5%	55.0%	Common Equity Ratio	51.0%
1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	4346.2	3987.9	4461.5	4315	4800	Total Capital ($mill)	7000
1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	4439.1	4793.1	5147.9	5475	5800	Net Plant ($mill)	6700
6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	5.9%	6.9%	6.1%	6.0%	6.0%	Return on Total Cap'l	5.5%
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.0%	8.0%	Return on Shr. Equity	8.0%
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.0%	8.0%	Return on Com Equity	8.0%
1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	3.3%	3.0%	3.5%	Retained to Com Eq	3.5%
82%	70%	77%	73%	63%	65%	65%	68%	62%	62%	65%	59%	All Div'ds to Net Prof	54%

CAPITAL STRUCTURE as of 6/30/12
Total Debt $2419.9 mill. **Due in 5 Yrs** $660.0 mill.
LT Debt $1956.3 mill. **LT Interest** $110.0 mill.
(LT interest earned: 3.1x; total interest coverage: 3.1x)
Leases, Uncapitalized Annual rentals $17.7 mill.
Pfd Stock None
Pension Assets-9/11 $280.2 mill. **Oblig.** $429.4 mill.
Common Stock 90,173,217 shs. **as of 8/3/12**
MARKET CAP: $3.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	132.0	131.4	27.7
Other	743.2	879.6	748.0
Current Assets	875.2	1011.0	775.7
Accts Payable	266.2	291.2	178.2
Debt Due	486.2	208.8	463.6
Other	413.7	367.6	468.4
Current Liab.	1166.1	867.6	1110.2
Fix. Chg. Cov.	440%	432%	430%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.5%	-3.5%	3.5%
"Cash Flow"	4.5%	4.5%	3.5%
Earnings	7.0%	4.0%	4.0%
Dividends	1.5%	1.5%	1.5%
Book Value	6.5%	4.5%	6.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1716.3	1821.4	780.8	650.6	4969.1
2010	1292.9	1940.3	770.2	786.3	4789.7
2011	1133.3	1581.5	843.6	789.2	4347.6
2012	1084.0	1225.5	576.4	552.6	3438.5
2013	1095	1300	725	680	3800

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	.83	1.29	.02	d.17	1.97
2010	1.00	1.17	d.03	.02	2.16
2011	.81	1.40	.04	.01	2.26
2012	.68	1.12	.31	- -	2.10
2013	.74	1.36	.22	.03	2.35

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.325	.325	.325	.33	1.31
2009	.33	.33	.33	.335	1.33
2010	.335	.335	.335	.34	1.35
2011	.34	.34	.34	.345	1.37
2012	.345	.345	.345	.35	

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three 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 2011 gas volumes: 281.5 MMcf. Breakdown: 57%, residential; 32%, commercial; 7%, industrial; and 4% other. 2011 depreciation rate 3.3%. Has around 4,750 employees. Officers and directors own 1.5% of common stock (12/11 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Inc.: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

We believe that Atmos Energy will stage an earnings turnaround in the new fiscal year, which began on October 1st. The core natural gas distribution segment stands to benefit from a rise in throughput, if weather conditions cooperate (leading to a boost in consumption levels). Moreover, the other operations, including the natural gas marketing business and pipeline unit, ought to perform reasonably well, overall. As a result, we expect consolidated share net to climb about 12%, to $2.35, in fiscal 2013. Assuming additional expansion of operating margins, the bottom line could well advance roughly 5% or so, to $2.45 a share, the following year.

Steady, although unspectacular, results appear to be in store for the company over the 2015-2017 time frame. The utility ranks as one of the country's biggest natural gas-only distributors, boasting roughly three million customers across nine states. Furthermore, the other businesses, especially pipelines, possess healthy overall expansion prospects. Finally, we believe that the company will eventually resume its successful strategy of purchasing less efficient utilities and shoring up their profitability through expense-reduction efforts, rate relief, and aggressive marketing initiatives. (The last major transaction occurred in October, 2004, when Atmos Energy bought TXU Gas Company.) But given our exclusion of future acquisitions, because of size and timing issues, annual earnings-per-share growth may be in the mid-single-digit range over the coming three to five years.

The stock offers an appealing dividend yield, which is higher than the average of all gas utility equities tracked by *Value Line*. Our 2015-2017 projections indicate that further, albeit moderate, increases in the distribution are likely to take place. The payout ratio ought to remain within a manageable range (i.e., 50% to 60%). What's more, these shares currently hold a 2 (Above Average) rank for both Safety and Timeliness, as well as an excellent score for Price Stability. All things considered, a variety of investors might wish to take a look here.

Frederick L. Harris, III *December 7, 2012*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '03, d17¢; '06, d18¢; '07, d2¢; '09, 12¢; '10, 5¢; '11, (1¢). Excludes discontinued operations: '11, 10¢; '12, 27¢. Next egs. rpt. due early Feb. (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	50
Earnings Predictability	90

LACLEDE GROUP NYSE-LG

RECENT PRICE	39.89	P/E RATIO	13.7 (Trailing: 14.3 Median: 14.0)	RELATIVE P/E RATIO	0.92	DIV'D YLD	4.3%	VALUE LINE

TIMELINESS 3 Lowered 9/23/11

SAFETY 2 Raised 6/20/03

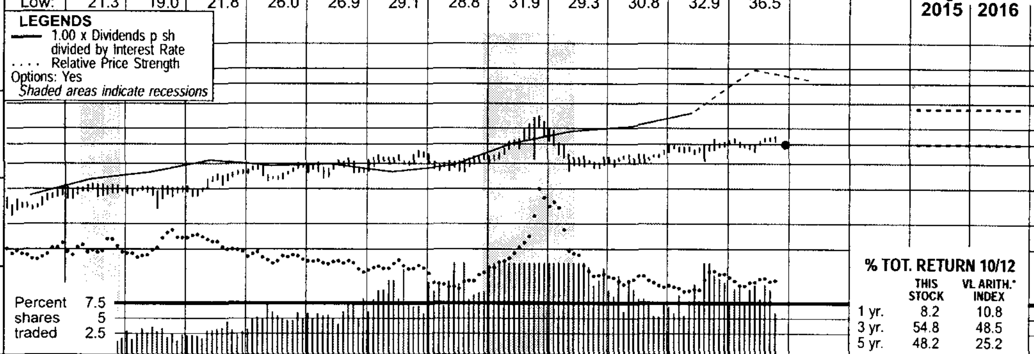
TECHNICAL 3 Lowered 11/23/12

BETA .55 (1.00 = Market)

High:	25.5	25.0	30.0	32.5	34.3	37.5	36.0	55.8	48.3	37.8	42.8	44.0	
Low:	21.3	19.0	21.8	26.0	26.9	29.1	28.8	31.9	29.3	30.8	32.9	36.5	

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+50%)	14%
Low	45	(+15%)	6%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	64	62	62
to Sell	58	71	64
Hld's(000)	10812	11161	10921

Percent shares traded 7.5 5 2.5

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.2	10.8
3 yr.	54.8	48.5
5 yr.	48.2	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
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	85.49	77.83	71.48	49.76	50.40	Revenues per sh A	52.00
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	4.56	4.11	4.62	4.58	4.65	"Cash Flow" per sh	5.20
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	2.92	2.43	2.86	2.79	2.85	Earnings per sh A B	3.30
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	1.61	1.66	1.74	Div'ds Decl'd per sh C ■	1.84
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	2.36	2.56	3.02	4.71	2.85	Cap'l Spending per sh	3.00
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	23.32	24.02	25.56	26.60	28.35	Book Value per sh D	33.00
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	22.17	22.29	22.43	22.62	23.0	Common Shs Outst'g E	23.5
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	13.4	13.7	13.0	14.5		Avg Ann'l P/E Ratio	15.5
.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	.86	.89	.87	.81	.97		Relative P/E Ratio	1.05
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%	3.9%	4.7%	4.3%	4.1%		Avg Ann'l Div'd Yield	3.8%

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
755.2	1050.3	1250.3	1597.0	1997.6	2021.6	2209.0	1895.2	1735.0	1603.3	1125.5	1150	Revenues ($mill) A	1225
22.4	34.6	36.1	40.1	50.5	49.8	57.6	64.3	54.0	63.8	63.1	65.0	Net Profit ($mill)	78.0
35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	31.3%	33.6%	33.4%	31.4%	32.0%	31.0%	Income Tax Rate	33.0%
3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	2.6%	3.4%	3.1%	4.0%	5.6%	5.6%	Net Profit Margin	6.4
47.5%	50.4%	51.6%	48.1%	49.5%	45.3%	44.4%	42.9%	40.5%	38.9%	36.0%	38.5%	Long-Term Debt Ratio	37.5%
52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	55.5%	57.1%	59.5%	61.1%	64.0%	61.5%	Common Equity Ratio	62.5%
546.6	605.0	737.4	707.9	798.9	784.5	876.1	906.3	899.9	937.7	941.0	1050	Total Capital ($mill)	1240
594.4	621.2	646.9	679.5	763.8	793.8	823.2	855.9	884.1	928.7	1019.3	1025	Net Plant ($mill)	1100
6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	8.1%	8.7%	7.4%	8.1%	6.5%	7.5%	Return on Total Cap'l	7.5%
7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.6%	9.5%	Return on Shr. Equity	10.0%
7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.6%	9.5%	Return on Com Equity	10.0%
NMF	3.1%	2.7%	3.1%	5.1%	4.3%	5.2%	5.9%	3.6%	4.9%	4.3%	4.0%	Retained to Com Eq	4.5%
NMF	74%	73%	72%	59%	63%	56%	53%	64%	56%	60%	61%	All Div'ds to Net Prof	55%

CAPITAL STRUCTURE as of 9/30/12
Total Debt $364.4 mill. **Due in 5 Yrs** $50.0 mill.
LT Debt $339.4 mill. **LT Interest** $25.0 mill.
(Total interest coverage: 4.6x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/11 $248.0 mill. **Oblig.** $384.2 mill.

Pfd Stock None

Common Stock 22,262,000 shs. as of 9/30/12

MARKET CAP: $900 million (Small Cap)

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	86.9	43.3	27.5
Other	327.3	325.8	315.5
Current Assets	414.2	369.1	343.0
Accts Payable	95.6	96.6	89.5
Debt Due	154.6	46.0	25.0
Other	83.7	89.3	137.6
Current Liab.	333.9	231.9	252.1
Fix. Chg. Cov.	391%	463%	242%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	8.0%	.5%	-6.5%
"Cash Flow"	5.0%	7.0%	2.5%
Earnings	6.5%	6.0%	3.0%
Dividends	1.5%	2.5%	2.5%
Book Value	5.0%	6.5%	4.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	674.3	659.1	309.9	251.9	1895.2
2010	491.2	635.3	324.5	284.0	1735.0
2011	444.2	543.8	344.3	271.0	1603.3
2012	410.9	358.2	186.9	169.5	1125.5
2013	365	400	210	175	1150

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1.42	1.40	.31	d.22	2.92
2010	1.03	1.26	.21	d.07	2.43
2011	1.05	1.25	.69	d.13	2.86
2012	1.12	1.32	.38	d.03	2.79
2013	1.20	1.35	.40	d.10	2.85

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.375	.375	.375	.375	1.50
2009	.385	.385	.385	.385	1.54
2010	.395	.395	.395	.395	1.58
2011	.405	.405	.405	.405	1.62
2012	.415	.415	.415	.415	

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 628,000 customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Utility therms sold and transported in fiscal 2012: 1.0 bill. Revenue mix for regulated operations: residential, 64; commercial and industrial, 21%; transportation, 2%; other, 13%. Has around 1,640 employees. Officers and directors own approximately 8% of common shares (1/12 proxy). Chairman: William E. Nasser; CEO: Suzanne Sitherwood. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Laclede Group's fourth-quarter results were better than expected (Years end September). Revenues decreased to $169.5 million, due to lower commodities costs, which were passed through to natural gas customers. Losses were narrowed to $0.03 a share compared to last year's deficit of $0.13. Margin expansion (5.6% in 2012 versus 4.0% in 2011) played a major factor in this year's earnings decreasing only slightly, even though there was a large decline in sales.

Increases in infrastructure replacement spending are a key component of Laclede's growth strategy. Over half of the $115 million spent on infrastructure is eligible to be recovered through the Infrastructure System Replacement Surcharge (ISRS), which charges customers for infrastructure replacement and improvement. This program leads to higher fixed revenues with greater margins, which allows for more consistent financial results.

Laclede is investing in emerging technologies in its non-regulated division, such as compressed natural gas (CNG) for vehicles. This segment advanced 37% over fiscal 2011. Commercial vehicle fleets, like the one at AT&T, are increasingly using CNG as an economical fuel source. As this trend plays out, Laclede's earnings will increasingly come from the nonregulated gas division, which should grow margins further.

Laclede raised its quarterly dividend to $0.425 a share, increasing the payout by 2.4% per year. The share price has come down since our last report bringing the yield up to 4.3%. This is well covered by earnings. Dividend growth has the potential to be quite noticeable over the next few years. This is the 10th year in a row that Laclede has raised its dividend, and this trend is likely to persist.

Laclede has a Timeliness rank of 3 (Average). This issue is likely to track the broader averages over the next six to 12 months. Its Above-Average Safety rank and growing dividend may appeal to income investors. This dividend also has the potential to be one of the strongest in the natural gas distribution field, thanks to the company's stronger-than-average cash flow potential.

John E. Seibert III *December 7, 2012*

(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 January. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '11: $429.9 mill., $19.17/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	50
Earnings Predictability	80

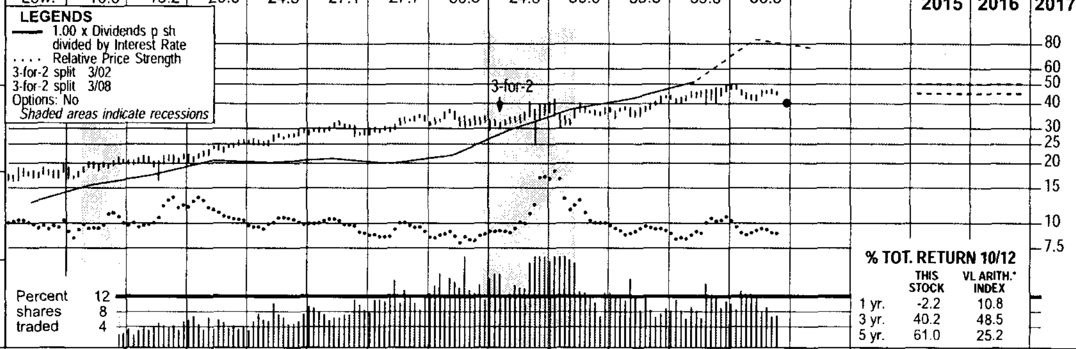
NEW JERSEY RES. NYSE-NJR

RECENT PRICE	40.33	P/E RATIO	14.1 (Trailing: 13.4 / Median: 15.0)	RELATIVE P/E RATIO	0.95	DIV'D YLD	4.0%	VALUE LINE

TIMELINESS 3 Raised 9/14/12
SAFETY 1 Raised 9/15/06
TECHNICAL 3 Lowered 11/30/12
BETA .65 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	21.7	22.4	26.4	29.7	32.9	35.4	37.6	41.1	42.4	44.1	50.5	50.3
Low:	16.6	16.2	20.0	24.3	27.1	27.7	30.3	24.6	30.0	33.5	39.6	38.5

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/02
3-for-2 split 3/08
Options: No
Shaded areas indicate recessions



Target Price Range
2015 | 2016 | 2017

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	45	(+10%)	7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	1	0	0	0	0	0	0	0
Options	0	1	0	0	0	0	0	0	0
to Sell	0	2	0	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	66	75	68
to Sell	65	71	80
Hld's(000)	24285	24119	23904

Percent shares traded 12 8 4

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.2	10.8
3 yr.	40.2	48.5
5 yr.	61.0	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
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	62.34	64.10	72.60	54.16	*70.00*	Revenues per sh A	*76.50*
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	3.16	3.26	3.40	*3.74*	*3.85*	"Cash Flow" per sh	*4.45*
.92	.99	1.04	1.11	1.20	1.30	1.39	1.59	1.70	1.77	1.87	1.55	2.70	2.40	2.46	2.58	2.71	*2.90*	Earnings per sh B	*3.40*
.69	.71	.73	.75	.76	.78	.80	.83	.87	.91	.96	1.01	1.11	1.24	1.36	1.44	1.52	*1.60*	Div'ds Decl'd per sh C■	*1.68*
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	1.81	2.10	2.26	*2.00*	*2.00*	Cap'l Spending per sh	*2.00*
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	16.59	17.62	18.73	*18.15*	*19.10*	Book Value per sh D	*24.20*
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	41.59	41.17	41.45	41.53	*40.00*	Common Shs Outst'g E	*40.00*
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	14.9	15.0	16.8	16.8		Avg Ann'l P/E Ratio	*14.0*
.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.87	1.15	.74	.99	.95	1.05	1.08		Relative P/E Ratio	*.95*
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%	3.5%	3.7%	3.3%	3.3%		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $812.8 mill. **Due in 5 Yrs** $214.3 mill.
LT Debt $525.2 mill. **LT Interest** $19.6 mill.
Incl. $65.8 mill. capitalized leases.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Pension Assets-9/12 $207.8 mill. **Oblig.** $332.2 mill.
Pfd Stock None
Common Stock 41,689,123 shs. **as of 11/23/12**
MARKET CAP: $1.7 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
1830.8	2544.4	2533.6	3148.3	3299.6	3021.8	3816.2	2592.5	2639.3	3009.2	2248.9	*2800*	Revenues ($mill) A	*3060*
56.8	65.4	71.6	74.4	78.5	65.3	113.9	101.0	101.8	106.5	*112*	*120*	Net Profit ($mill)	*140*
38.7%	39.4%	39.1%	39.1%	38.9%	38.8%	37.8%	27.1%	41.4%	30.2%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
3.1%	2.6%	2.8%	2.4%	2.4%	2.2%	3.0%	3.9%	3.9%	3.5%	*5.0%*	*4.3%*	Net Profit Margin	*4.5%*
50.6%	38.1%	40.3%	42.0%	34.8%	37.3%	38.5%	39.8%	37.2%	35.5%	39.2%	*39.5%*	Long-Term Debt Ratio	*34.0%*
49.4%	61.9%	59.7%	58.0%	65.2%	62.7%	61.5%	60.2%	62.8%	64.5%	60.8%	*60.5%*	Common Equity Ratio	*66.0%*
732.4	676.8	783.8	755.3	954.0	1028.0	1182.1	1144.8	1154.4	1203.1	1339.0	*1265*	Total Capital ($mill)	*1470*
756.4	852.6	880.4	905.1	934.9	970.9	1017.3	1064.4	1135.7	1295.9	1484.9	*1350*	Net Plant ($mill)	*1430*
8.7%	10.7%	10.1%	11.2%	9.6%	7.7%	10.7%	9.7%	9.7%	9.7%	*9.5%*	*10.5%*	Return on Total Cap'l	*10.0%*
15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	*14.0%*	*16.0%*	Return on Shr. Equity	*14.0%*
15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	*14.0%*	*16.0%*	Return on Com Equity	*14.0%*
6.9%	7.7%	7.8%	8.5%	6.3%	3.6%	9.5%	7.2%	6.7%	6.2%	*6.0%*	*7.5%*	Retained to Com Eq	*7.5%*
56%	51%	49%	50%	50%	64%	40%	50%	52%	55%	*56%*	*53%*	All Div'ds to Net Prof	*49%*

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	.9	7.4	4.5
Other	784.1	725.0	642.8
Current Assets	785.0	732.4	647.3
Accts Payable	47.3	66.0	265.8
Debt Due	178.9	166.9	287.6
Other	479.6	470.5	99.7
Current Liab.	705.8	703.4	653.1
Fix. Chg. Cov.	700%	700%	700%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	7.0%	-1.5%	*2.5%*
"Cash Flow"	5.0%	4.5%	*5.0%*
Earnings	7.5%	7.0%	*5.5%*
Dividends	6.0%	8.0%	*4.0%*
Book Value	8.0%	7.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	801.3	937.5	441.1	412.6	2592.5
2010	609.6	918.4	479.8	631.5	2639.3
2011	713.2	977.0	648.1	670.9	3009.2
2012	642.4	612.9	425.1	568.5	2248.9
2013	*790*	*765*	*575*	*670*	*2800*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	.77	1.71	.03	d.12	2.40
2010	.66	1.55	.28	d.03	2.46
2011	.71	1.62	.23	.02	2.58
2012	1.09	1.79	.10	d.27	2.71
2013	*1.15*	*1.84*	*.15*	*d.24*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.31	.31	.31	.31	1.24
2010	.34	.34	.34	.34	1.36
2011	.36	.36	.36	.36	1.44
2012	.38	.38	.38	.38	1.52
2013	.40				

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 494,964 customers at 9/30/11 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2011 volume: 178 bill. cu. ft. (5% interruptible, 35% residential and commercial and electric utility, 60% incentive programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2011 dep. rate: 2.2%. Has 891 empls. Off./dir. own about 1.1% of common (12/11 Proxy). Chrmn., CEO & Pres. : Laurence M. Downes. Inc.: NJ Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

New Jersey Resources posted a mixed bag of financial results for fiscal 2012 (ended September 30th). Indeed, the top line declined approximately 25% on a year-over-year basis. This reflected diminished volumes at both the utility and nonutility divisions. However, this was not alarming, being largely due to lower year-to-year comparable natural gas prices. Overall, management was successful at trimming unnecessary expenses, thereby boosting profitability for the year. And, on balance, NJR logged a modest 5% earnings advance, to $2.71 a share. However, this was slightly lower than we had previously anticipated. Consequently,

We have reduced our top- and bottom-line estimates for 2013 accordingly. Helped by low natural gas prices, New Jersey Resources has been quite successful at growing the number of customer accounts at the New Jersey Natural Gas regulated utility division. That unit comprises the bulk of the company's business mix, and is expected to add 6,000 to 7,000 new customers this year alone. Elsewhere, the NJR Clean Energy Ventures segment has multiple capital projects for alternative energy investments in its pipeline. On the downside, the NJR Energy services unit will likely continue to experience difficulties this year, as historically low natural gas prices and reduced volatility weigh on the wholesale market's profitability. Meanwhile, cost-cutting efforts that helped to boost the bottom line in 2012, will not be as effective with sustained top-line weakness this year. Thus, we have reduced our earnings estimate by $0.25, to $2.90 a share, for fiscal 2013.

The board recently approved a quarterly divided increase of about 5%, to $0.40 a share. This payout came on the heels of the regularly scheduled fourth-quarter dividend, due to concerns that the tax rate on dividends may rise next year.

These neutrally ranked shares are trading down roughly 13% in price since our September review. The bulk of this move likely stemmed from concerns for how the effects of Hurricane Sandy may weigh on the company's operations, as well as general concerns over higher taxes on dividends and capital gains.

Bryan J. Fong *December 7, 2012*

(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 Jan.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2011: $434.2 million, $10.48/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	50

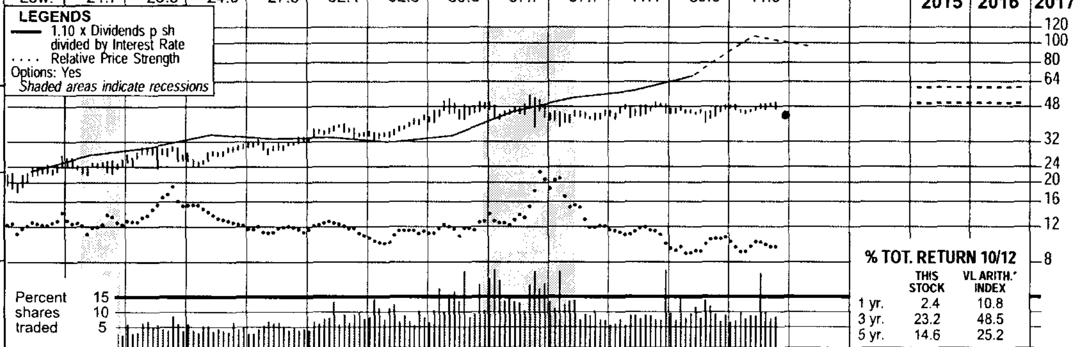
N.W. NAT'L GAS NYSE-NWN

RECENT PRICE	43.28	P/E RATIO	18.5 (Trailing: 18.4 / Median: 17.0)	RELATIVE P/E RATIO	1.15	DIV'D YLD	4.2%	VALUE LINE

TIMELINESS 3 Raised 9/21/12
SAFETY 1 Raised 3/18/05
TECHNICAL 3 Lowered 12/7/12
BETA .55 (1.00 = Market)

High:	26.8	30.7	31.3	34.1	39.6	43.7	52.8	55.2	46.5	50.9	49.0	50.8	
Low:	21.7	23.5	24.0	27.5	32.4	32.8	39.8	37.7	37.7	41.1	39.6	41.0	

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+40%)	12%
Low	50	(+15%)	8%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	2	0	1	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	72	69	70
to Sell	43	58	51
Hld's(000)	16071	16355	16429

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.4	10.8
3 yr.	23.2	48.5
5 yr.	14.6	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	29.25	29.10	Revenues per sh	30.55
3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	4.50	4.60	"Cash Flow" per sh	4.95
1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.39	2.25	2.45	Earnings per sh A	3.15
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	1.60	1.68	1.75	1.79	1.83	Div'ds Decl'd per sh B ■	1.96
3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	5.09	9.35	3.76	6.60	7.00	Cap'l Spending per sh	8.10
15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	26.95	27.35	Book Value per sh D	27.75
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	26.53	26.58	26.76	27.00	27.50	Common Shs Outst'g C	28.00
11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	Bold figures are		Avg Ann'l P/E Ratio	17.0
.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.08	1.20	Value Line		Relative P/E Ratio	1.15
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%	3.7%	3.6%	3.9%	estimates		Avg Ann'l Div'd Yield	3.3%

CAPITAL STRUCTURE as of 9/30/12
Total Debt $817.5 mill. Due in 5 Yrs $200 mill.
LT Debt $641.7 mill. LT Interest $45.0 mill.

(Total interest coverage: 3.4x)

Pension Assets-12/11 $216 mill. Oblig. $391.1 mill.

Pfd Stock None

Common Stock 26,902,000 shares

MARKET CAP $1.2 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	1012.7	812.1	848.8	790	800	Revenues ($mill)	855
43.8	46.0	50.6	58.1	65.2	74.5	68.5	75.1	72.7	63.9	60.0	70.0	Net Profit ($mill)	90.0
34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	38.3%	40.5%	40.4%	38.5%	36.0%	Income Tax Rate	32.5%
6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	7.4%	8.9%	7.5%	8.1%	8.8%	Net Profit Margin	10.3%
47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	47.7%	46.1%	47.3%	47.0%	47.0%	Long-Term Debt Ratio	48.5%
51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	52.3%	53.9%	52.7%	53.0%	53.0%	Common Equity Ratio	52.5%
937.3	1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	1261.8	1284.8	1356.2	1370	1410	Total Capital ($mill)	1515
995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.1	1670.1	1854.2	1893.9	1985	1895	Net Plant ($mill)	1895
5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	7.7%	7.3%	7.0%	6.2%	6.0%	6.5%	Return on Total Cap'l	7.0%
8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	8.5%	9.5%	Return on Shr. Equity	11.5%
8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	8.5%	9.0%	Return on Com Equity	11.5%
1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.5%	5.0%	4.0%	2.4%	2.5%	3.0%	Retained to Com Eq	4.0%
79%	72%	69%	63%	59%	52%	59%	56%	61%	73%	80%	75%	All Div'ds to Net Prof	62%

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	3.5	5.8	5.7
Other	326.8	342.9	192.2
Current Assets	330.3	348.7	197.9
Accts Payable	93.2	86.3	61.3
Debt Due	267.4	181.6	175.8
Other	107.6	146.6	108.3
Current Liab.	468.2	414.5	345.4
Fix. Chg. Cov.	366%	334%	344%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	1.0%	-1.5%
"Cash Flow"	3.0%	3.5%	-0.5%
Earnings	4.0%	4.5%	3.0%
Dividends	3.0%	4.5%	2.5%
Book Value	4.0%	4.0%	1.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	437.4	149.1	116.9	309.3	1012.7
2010	286.5	162.4	95.1	268.1	812.1
2011	323.1	161.2	93.3	271.2	848.8
2012	317.5	106.6	89.8	276.1	790
2013	315	140	90	255	800

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.78	.12	d.25	1.18	2.83
2010	1.64	.26	d.28	1.11	2.73
2011	1.53	.08	d.31	1.09	2.39
2012	1.51	.05	d.39	1.08	2.25
2013	1.50	.15	d.25	1.05	2.45

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.375	.375	.375	.395	1.52
2009	.395	.395	.395	.415	1.60
2010	.415	.415	.415	.435	1.68
2011	.435	.435	.435	.445	1.75
2012	.445	.445	.445	.455	

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 681,000 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, 57%; commercial, 26%; industrial, gas transportation, and other, 17%. Employs 1,061. BlackRock Inc. owns 7.8% of shares; officers and directors, 1.7% (4/12 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 Gas Co.'s third-quarter results were mixed. Revenues decreased to $89.8 million, down 4% year over year. Losses narrowed to $0.29 a share compared to last year's $0.31. Margins expanded while sales declined. Increases in natural gas storage income (up 8%) likely will have a small but positive effect on profits and sales.

NW Natural received mixed results from a base rate case filed in Oregon. The Oregon Public Utility Commission (PUC) allowed the company to collect higher fixed charges, increasing revenues by $8.7 million. The PUC also lowered rates that NW Natural charges for natural gas. Although margins should decline as a result of this rate decrease, total volume should increase over the next few years, somewhat limiting the downside effect. As a result, we have lowered our earnings estimate for 2012 to $2.25 a share from $2.45. The higher fixed charges could lower earnings variability. Pension cost base-rate decisions were deferred by the PUC, but the outcome will have an effect on future profitability.

NW Natural is focused on increasing its industrial customer base. By filing to lower the base rate by 14%, the company would entice more businesses to switch to natural gas for their processes. This would potentially grow and diversify the customer base while increasing revenues. The company is also on track with its joint venture with Encana in the Jonah field, which should produce 8%-10% of the annual natural gas requirements. Both these initiatives are crucial to long-term growth.

NW Natural has raised its annual dividend to $1.82 a share. This is the 57th consecutive year that the company has increased its dividend and this trend is likely to continue. The stock retreat since our last report and the dividend increase have caused the yield to expand, but it is still below average for gas utilities.

NW Natural has a Timeliness rank of 3 (Average). Although this issue has below market average appreciation potential, conservative investors with an income objective should consider this issue because it has a high and growing yield and Highest Safety rank (1); however, this issue is not for performance-minded investors.

John E. Seibert III *December 7, 2012*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03); '09, 6¢; Next earnings report due late January.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2011: $371.4 million, $13.88/share.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	90

PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE **30.34** | P/E RATIO **17.8** (Trailing: 19.4 Median: 18.0) | RELATIVE P/E RATIO **1.20** | DIV'D YLD **4.0%** | VALUE LINE

TIMELINESS 3 Raised 6/22/12

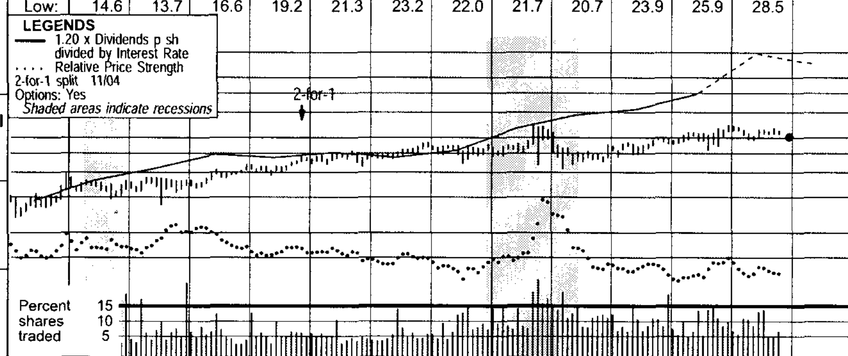
SAFETY 2 New 7/27/90

TECHNICAL 2 Raised 11/2/12

BETA .65 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
High:	19.0	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0	30.1	34.7	34.6
Low:	14.6	13.7	16.6	19.2	21.3	23.2	22.0	21.7	20.7	23.9	25.9	28.5

LEGENDS
— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 11/04
Options: Yes
Shaded areas indicate recessions



Target Price Range
2015 | 2016 | 2017

80 – 60 – 50 – 40 – 30 – 25 – 20 – 15 – 10 – 7.5

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+30%)	11%
Low	30	(Nil)	4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
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	1	2	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	85	68	84
to Sell	85	92	74
Hld's(000)	32579	32684	33222

Percent shares traded 15 10 5

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.1	10.8
3 yr.	52.2	48.5
5 yr.	50.0	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
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	22.36	21.48	19.83	*15.75*	*17.85*	Revenues per sh A	*20.10*
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	3.01	2.91	2.99	*3.05*	*3.20*	"Cash Flow" per sh	*3.45*
.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	1.67	1.55	1.57	*1.60*	*1.70*	Earnings per sh AB	*1.85*
.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.07	1.11	1.15	1.19	*1.23*	Div'ds Decl'd per sh C■	*1.35*
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	1.76	2.75	3.37	*7.75*	*7.85*	Cap'l Spending per sh	*8.10*
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	12.67	13.35	13.79	*13.85*	*14.00*	Book Value per sh D	*14.60*
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	73.27	72.28	72.32	*71.00*	*70.00*	Common Shs Outst'g E	*68.00*
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	15.4	17.1	18.9	*19.9*		Avg Ann'l P/E Ratio	*18.0*
.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.10	1.03	1.09	1.19	*1.28*		Relative P/E Ratio	*1.20*
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%	4.1%	4.2%	3.9%	3.7%		Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 7/31/12
Total Debt $1175.0 mill. **Due in 5 Yrs** $175.0 mill.
LT Debt $975.0 mill. **LT Interest** $46.1 mill.
(LT interest earned: 4.1x; total interest coverage: 3.4x)

Pension Assets-10/11 $259.5 mill. **Oblig.** $236.6 mill.

Pfd Stock None

Common Stock 72,076,431 shs. **as of 9/4/12**

MARKET CAP: $2.2 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
832.0	1220.8	1529.7	1761.1	1924.6	1711.3	2089.1	1638.1	1552.3	1433.9	*1120*	*1250*	Revenues ($mill) A	*1365*
62.2	74.4	95.2	101.3	97.2	104.4	110.0	122.8	111.8	113.6	*115*	*120*	Net Profit ($mill)	*125*
33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.3%	28.5%	23.4%	24.6%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	7.5%	7.2%	7.9%	*10.2%*	*9.6%*	Net Profit Margin	*9.3%*
43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	44.1%	41.0%	40.4%	*49.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	55.9%	59.0%	59.6%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	1660.5	1636.9	1671.9	*1960*	*1955*	Total Capital ($mill)	*1995*
1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	2304.4	2437.7	2627.3	*2900*	*2950*	Net Plant ($mill)	*3050*
7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	9.1%	8.4%	8.2%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.5%*
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	*11.5%*	*12.0%*	Return on Shr. Equity	*12.5%*
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	*11.5%*	*12.0%*	Return on Com Equity	*12.5%*
1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	4.8%	3.3%	3.1%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
83%	74%	66%	68%	74%	70%	69%	64%	72%	73%	74%	*72%*	All Div'ds to Net Prof	*73%*

CURRENT POSITION ($MILL.)

	2010	2011	7/31/12
Cash Assets	5.6	6.8	5.7
Other	322.2	279.2	283.4
Current Assets	327.8	286.0	289.1
Accts Payable	115.7	129.7	117.9
Debt Due	302.0	331.0	200.0
Other	80.9	72.9	80.4
Current Liab.	498.6	534.1	398.3
Fix. Chg. Cov.	323%	323%	325%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	-1.5%	*-1.0%*
"Cash Flow"	5.5%	4.0%	*2.5%*
Earnings	5.0%	4.5%	*2.5%*
Dividends	4.5%	4.0%	*3.5%*
Book Value	5.0%	3.0%	*1.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	779.6	455.4	180.3	222.8	1638.1
2010	673.7	472.9	211.6	194.1	1552.3
2011	652.0	392.6	197.3	192.0	1433.9
2012	471.8	308.4	161.1	*178.7*	*1120*
2013	*505*	*340*	*195*	*210*	*1250*

Fiscal Year Ends	EARNINGS PER SHARE A B Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	1.10	.73	d.10	d.06	1.67
2010	1.14	.65	d.13	d.13	1.55
2011	1.16	.66	d.12	d.13	1.57
2012	1.05	.70	d.06	*d.09*	*1.60*
2013	*1.18*	*.70*	*d.09*	*d.09*	*1.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.25	.26	.26	.26	1.03
2009	.26	.27	.27	.27	1.07
2010	.27	.28	.28	.28	1.11
2011	.28	.29	.29	.29	1.15
2012	.29	.30	.30	.30	

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 968,188 customers in North Carolina, South Carolina, and Tennessee. 2011 revenue mix: residential (46%), commercial (27%), industrial (7%), other (20%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 60.0% of revenues. '11 deprec. rate: 3.2%. Estimated plant age: 10 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,782 employees. Off./dir. own about 1.2% of common stock, BlackRock; 7.6% (1/12 proxy). Chrmn., CEO, & Pres.: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas likely posted a mixed bag of financial results for fiscal 2012 (ended October 31st). Indeed, we expect a year-to-year top-line decline of approximately 22%. This is largely a reflection of lower pass-through costs for natural gas. Meanwhile, on the profitability front, the company has been successful in trimming its cost of goods sold for the bulk of the year, and we expect that trend continued in the fourth quarter and for the year, as a whole. Customer additions were another boon to the bottom line. At the end of the third quarter, Piedmont had added more than 8,700 accounts to its system. Elsewhere, gains ought to have stemmed from a rise in income from equity-method investments, as higher contributions come in from the energy services and pipeline divisions. Combined, we think PNY's 2012 share-net figure ticked about 2% higher, to $1.60.

Capital projects augur well for prospects down the road. At this point, Piedmont finished the first four power generation delivery projects for Duke Energy. The fifth project, related to the Sutton Facility, is well under way, and has a targeted in-service date of June, 2013. These developments equate to an investment of $500 million, and they are boosting throughput on the Cardinal Pipeline.

We look for steady top- and bottom-line advances in fiscal 2013. This ought to be supported by continued customer additions, a wider geographic footprint due to capital expenditures, and a diligent eye on efficiency initiatives. And a recently announced 24% equity stake in Constitution Pipeline Company, LLC., a natural gas pipeline project slated to be in service in 2015 adds to the PNY's prospects.

However, the financial position has deteriorated a bit over the course of the year. Cash reserves declined 16%, through the end of the third quarter (the last period for which financial information was available), to just under $6 million. And the company has taken on about 45% more long-term debt over this time frame.

These neutrally ranked shares have remained relatively steady since our September review. And PNY's yield is on par with the *Value Line* average for the utility group.

Bryan J. Fong *December 7, 2012*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring gains (losses): '97, (2¢); '10, 41¢. Next earnings report due mid Dec. Quarters may not add to total due to change in shares outstanding.
(C) Dividends historically paid early-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2011: $527.6 million, $7.29/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	95

SOUTH JERSEY INDS. NYSE-SJI

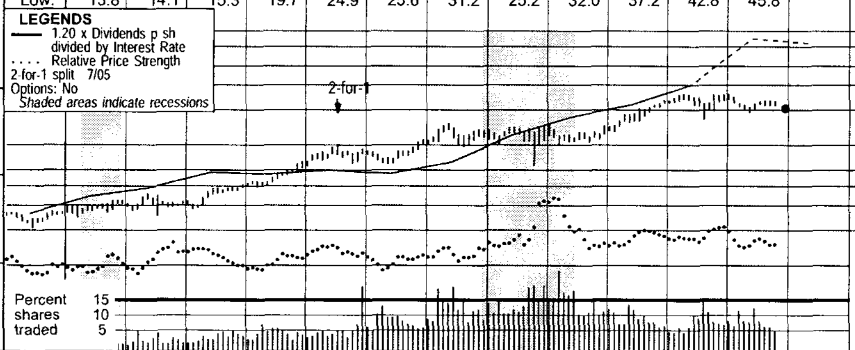
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
48.96	15.2	(Trailing: 15.7 Median: 15.0)	1.03	3.6%	VALUE LINE

TIMELINESS 3 Lowered 11/23/12
SAFETY 2 Lowered 1/4/91
TECHNICAL 2 Raised 10/19/12
BETA .65 (1.00 = Market)

High:	17.0	18.3	20.3	26.5	32.4	34.3	41.3	40.6	40.8	54.2	58.0	58.0
Low:	13.8	14.1	15.3	19.7	24.9	25.6	31.2	25.2	32.0	37.2	42.8	45.8

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: No
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+45%)	12%
Low	55	(+10%)	7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
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	3	0	1	3	0	3	2

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	59	68	78
to Sell	60	64	55
Hld's(000)	17847	17213	18018

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.3	10.8
3 yr.	56.9	48.5
5 yr.	57.3	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
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	28.37	30.97	27.42	**23.00**	**26.45**	Revenues per sh	**33.35**
1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	3.51	3.20	3.48	3.72	4.21	4.46	**4.60**	**4.75**	"Cash Flow" per sh	**6.25**
.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.09	2.27	2.38	2.70	2.89	**3.15**	**3.35**	Earnings per sh A	**4.50**
.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.11	1.22	1.36	1.50	**1.65**	**1.82**	Div'ds Decl'd per sh B ■	**2.30**
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	3.67	5.59	6.39	**6.20**	**6.45**	Cap'l Spending per sh	**7.20**
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	18.24	19.08	20.66	**23.00**	**24.60**	Book Value per sh C	**27.80**
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	29.80	29.87	30.21	**31.50**	**32.50**	Common Shs Outst'g D	**36.00**
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	15.0	16.8	18.4	*Bold figures are*		Avg Ann'l P/E Ratio	**14.0**
.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.07	1.16	*Value Line*		Relative P/E Ratio	**.95**
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%	3.4%	3.0%	2.8%	*estimates*		Avg Ann'l Div'd Yield	**3.7%**
						505.1	696.8	819.1	921.0	931.4	956.4	962.0	845.4	925.1	828.6	**725**	**860**	Revenues ($mill)	**1200**
						29.4	34.6	43.0	48.6	72.0	61.8	67.7	71.3	81.0	87.0	**100**	**105**	Net Profit ($mill)	**160**
						41.4%	40.6%	40.9%	41.5%	41.3%	41.9%	47.7%	23.0%	15.2%	22.4%	**20.0%**	**25.0%**	Income Tax Rate	**30.0%**
						5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	7.0%	8.4%	8.8%	10.5%	**13.8%**	**12.2%**	Net Profit Margin	**13.3%**
						53.6%	50.8%	48.7%	44.9%	44.7%	42.7%	39.2%	36.5%	37.4%	40.5%	**44.0%**	**43.0%**	Long-Term Debt Ratio	**43.0%**
						46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	60.8%	63.5%	62.6%	59.5%	**56.0%**	**57.0%**	Common Equity Ratio	**57.0%**
						512.5	608.4	675.0	710.3	801.1	839.0	848.0	856.4	910.1	1048.3	**1300**	**1400**	Total Capital ($mill)	**1750**
						666.6	748.3	799.9	877.3	920.0	948.9	982.6	1073.1	1193.3	1352.4	**1480**	**1600**	Net Plant ($mill)	**1900**
						7.6%	7.3%	7.9%	8.3%	10.1%	8.6%	8.9%	9.0%	9.5%	8.9%	**8.5%**	**8.0%**	Return on Total Cap'l	**9.5%**
						12.4%	11.5%	12.4%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	**14.0%**	**13.0%**	Return on Shr. Equity	**16.0%**
						12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	**14.0%**	**13.0%**	Return on Com Equity	**16.0%**
						4.7%	5.0%	5.9%	6.2%	10.2%	6.7%	6.7%	6.4%	7.1%	6.7%	**6.5%**	**5.5%**	Retained to Com Eq	**7.5%**
						62%	57%	52%	50%	37%	48%	49%	51%	50%	52%	**52%**	**56%**	All Div'ds to Net Prof	**52%**

CAPITAL STRUCTURE as of 9/30/12
Total Debt $906.8 mill. **Due in 5 Yrs** $434.0 mill.
LT Debt $566.4 mill. **LT Interest** $16.0 mill.
(Total interest coverage: 6.3x)

Pension Assets-12/11 $116.7 mill.
Oblig. $195.0 mill.

Pfd Stock None

Common Stock 31,262,570 common shs. as of 11/1/12

MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	2.4	7.5	4.2
Other	421.4	333.1	319.6
Current Assets	423.8	340.6	323.8
Accts Payable	165.2	153.7	111.1
Debt Due	362.1	323.6	340.4
Other	113.2	110.7	101.3
Current Liab.	640.5	588.0	552.8
Fix. Chg. Cov.	532%	505%	570%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	-1.5%	2.5%
"Cash Flow"	8.0%	8.0%	7.0%
Earnings	9.5%	7.0%	9.0%
Dividends	6.5%	9.5%	9.0%
Book Value	10.5%	7.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	362.2	134.5	127.1	221.6	845.4
2010	329.3	151.6	160.7	283.5	925.1
2011	331.9	160.5	137.6	198.6	828.6
2012	274.8	121.9	112.0	***216.3***	***725***
2013	***305***	***150***	***150***	***255***	***860***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.46	.15	d.06	.83	2.38
2010	1.49	.24	.10	.87	2.70
2011	1.63	.20	.01	1.05	2.89
2012	1.65	.28	.13	***1.09***	***3.15***
2013	***1.70***	***.30***	***.15***	***1.20***	***3.35***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	--	.270	.270	.568	1.11
2009	--	.298	.298	.628	1.22
2010	--	.330	.330	.695	1.36
2011	--	.365	.365	.768	1.50
2012	--	.403	.403	.845	

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 347,725 customers in New Jersey's southern counties, which covers about 2,500 square miles and includes Atlantic City. Gas revenue mix '11: residential, 41%; commercial, 20%; cogeneration and electric generation, 14%; industrial, 25%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 675 employees. Off./dir. control 1.0% of common shares; BlackRock Inc., 7.8% (3/12 proxy). Chrmn. & CEO: Edward Graham. Inc.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Telephone: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have pulled back somewhat over the past two months. Revenue declined for the third quarter, but that was largely due to a lower natural gas pricing environment. The mainstay utility segment reported a moderate top-line decline, and the nonutility businesses posted considerably lower revenues. But operating costs also declined, and the bottom-line picture was much brighter. Share net came in at $0.13, well above the prior-year tally.

The company appears to have made it through Hurricane Sandy in good shape. Flooding and high winds from the super storm dealt a significant blow to New Jersey residents. But service disruption at the utility was minimal, and SJI's nonutility energy projects experienced mostly superficial damage.

We look for moderate earnings growth going forward. We expect healthy results from most of SJI's businesses. Utility South Jersey Gas ought to benefit from modest customer growth going forward. Natural gas remains the fuel of choice within its service territory, and the utility should continue to benefit from customer interest in converting from other sources of fuel. In addition, spending on infrastructure projects under the Capital Investment Recovery Tracker program ought to improve service and allow the utility to earn a good return on these investments. On the nonutility side, healthy demand for renewable and natural gas-fired energy projects should benefit the Retail Energy line. Efforts to reposition the marketing unit may also bear fruit.

The board of directors has increased the dividend by roughly 10%. The quarterly dividend is now $0.4425 per share, beginning with the December payout. The company cited strong recent performance and myriad growth opportunities as reasons for the hike. Dividend increases will likely continue in the coming years.

These shares are neutrally ranked for Timeliness. We anticipate higher revenues and earnings for the company by 2015-2017. Moreover, South Jersey earns good marks for Safety, Price Stability, and Earnings Predictability. This equity offers decent, and fairly well-defined, total return potential for the coming years.

Michael Napoli, CFA *December 7, 2012*

(A) Based on GAAP egs. through 2006, economic egs. thereafter. GAAP EPS: '07, $2.10; '08, $2.58; '09, $1.94; '10, $2.22; '11, $2.97. Excl. nonrecur. gain (loss): '01, $0.13; '08, $0.31; '09, ($0.44); '10, ($0.47); '11, $0.08. Excl gain (losses) from discont. ops.: '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02); '07, $0.01. Next egs. report due in February. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2011: $315.2 mill., $10.43 per shr. (D) In mill., adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	85

SOUTHWEST GAS NYSE-SWX

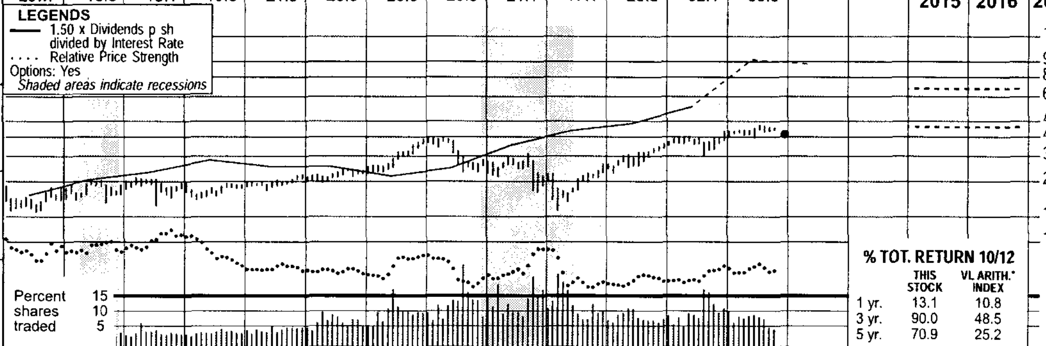
RECENT PRICE	41.30	P/E RATIO	13.8 (Trailing: 15.2 / Median: 17.0)	RELATIVE P/E RATIO	0.93	DIV'D YLD	3.1%	VALUE LINE

TIMELINESS 3 Lowered 11/16/12
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 8/10/12
BETA .75 (1.00 = Market)

High:	24.7	25.3	23.6	26.2	28.1	39.4	39.9	33.3	29.5	37.3	43.2	46.1
Low:	18.6	18.1	19.3	21.5	23.5	26.0	26.5	21.1	17.1	26.3	32.1	39.0

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+70%)	17%
Low	45	(+10%)	6%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	1	0	0	0	0	0	1
Options	0	0	2	0	0	2	0	0	1
to Sell	1	0	4	0	1	3	0	0	1

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	56	64	85
to Sell	95	79	70
Hld's(000)	34237	35127	34847

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.1	10.8
3 yr.	90.0	48.5
5 yr.	70.9	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
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	42.00	40.18	41.07	*42.25*	*43.10*	Revenues per sh	*52.00*
3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.76	6.16	6.46	6.81	*7.40*	*7.75*	"Cash Flow" per sh	*9.40*
.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	1.94	2.27	2.43	*2.72*	*2.85*	Earnings per sh A	*3.75*
.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	.95	1.00	1.06	*1.18*	*1.30*	Div'ds Decl'd per sh B■†	*1.60*
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	4.81	4.73	8.29	*7.85*	*8.50*	Cap'l Spending per sh	*9.60*
14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.49	24.44	25.62	26.66	*27.95*	*30.85*	Book Value per sh	*36.00*
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	45.09	45.56	45.96	*46.50*	*47.00*	Common Shs Outst'g C	*50.00*
69.3	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	12.2	14.0	15.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
4.34	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.22	.81	.89	.99	*Value Line*		Relative P/E Ratio	*1.00*
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%	4.0%	3.2%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*2.8%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $1261.1 mill. **Due in 5 Yrs** $343.0 mill.
LT Debt $1256.0 mill. **LT Interest** $70.0 mill.
(Total interest coverage: 3.8x) (50% of Cap'l)
Leases, Uncapitalized Annual rentals $6.0 mill.
Pension Assets-12/11 $551.8 mill. **Oblig.** $832.8 mill.
Pfd Stock None

Common Stock 46,140,788 shs. as of 10/26/12

MARKET CAP: $1.9 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	1893.8	1830.4	1887.2	*1965*	*2025*	Revenues ($mill)	*2600*
38.6	38.5	58.9	48.1	80.5	83.2	61.0	87.5	103.9	112.3	*125*	*135*	Net Profit ($mill)	*190*
32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	34.0%	34.7%	36.2%	*36.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	4.6%	5.7%	6.0%	*6.4%*	*6.7%*	Net Profit Margin	*7.3%*
62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	53.5%	49.1%	43.2%	*49.0%*	*48.0%*	Long-Term Debt Ratio	*48.5%*
34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	44.7%	46.5%	50.9%	56.8%	*51.0%*	*52.0%*	Common Equity Ratio	*51.5%*
1748.3	1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	2371.4	2291.7	2155.9	*2550*	*2800*	Total Capital ($mill)	*3500*
1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	3034.5	3072.4	3218.9	*3320*	*3400*	Net Plant ($mill)	*3750*
4.3%	4.2%	5.0%	4.3%	5.5%	5.5%	4.5%	5.4%	6.1%	6.4%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	*9.5%*	*9.5%*	Return on Com Equity	*10.5%*
1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	4.1%	5.1%	5.3%	*5.5%*	*5.0%*	Retained to Com Eq	*6.0%*
70%	72%	49%	65%	42%	44%	63%	48%	43%	43%	*44%*	*45%*	All Div'ds to Net Prof	*42%*

CURRENT POSITION ($MILL.)

	2010	2011	9/30/12
Cash Assets	116.1	21.9	22.1
Other	329.8	439.7	327.7
Current Assets	445.9	461.6	349.8
Accts Payable	165.5	186.8	90.6
Debt Due	75.1	322.6	5.1
Other	356.4	338.2	369.5
Current Liab.	597.0	847.6	465.2
Fix. Chg. Cov.	299%	359%	375%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	-1.5%	*4.0%*
"Cash Flow"	3.5%	3.0%	*6.5%*
Earnings	6.0%	6.5%	*9.0%*
Dividends	2.0%	4.0%	*8.0%*
Book Value	4.5%	5.0%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	689.9	387.6	317.5	498.8	1893.8
2010	668.8	385.8	307.7	468.1	1830.4
2011	628.4	388.5	352.6	517.7	1887.2
2012	657.6	409.8	371.8	*525.8*	*1965*
2013	*670*	*420*	*390*	*545*	*2025*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.12	d.01	d.18	1.01	1.94
2010	1.42	d.02	d.11	.98	2.27
2011	1.48	.09	d.34	1.19	2.43
2012	1.70	d.08	d.09	*1.19*	*2.72*
2013	*1.80*	*.10*	*d.30*	*1.25*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.215	.225	.225	.225	.89
2009	.225	.238	.238	.238	.94
2010	.238	.250	.250	.250	.99
2011	.250	.265	.265	.265	1.05
2012	.265	.295	.295	.295	

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.9 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2011 margin mix: residential and small commercial, 86%; large commercial and industrial, 4%; transportation, 10%. Total throughput: 2.1 billion therms. Sold PriMerit Bank, 7/96. Has 5,754 employees. Off. & Dir. own 1.6% of common stock; BlackRock Inc., 8.5%; GAMCO Investors, Inc., 8.3%; T. Rowe Price Associates, Inc., 6.7% (3/12 Proxy). Chairman: Michael J. Melarkey. CEO: Jeffrey W. Shaw. Inc.: CA. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas reported improved results for the third quarter. Revenues increased at a moderate clip, and the company posted a much lower share loss for the interim, partly because Southwest experienced healthy growth in the construction business. Utility revenues were roughly flat, compared with the prior-year period, but were supported by higher rates in Arizona. Efforts to control operating costs benefited the bottom line. We anticipate healthy results for the fourth quarter, and greater revenues and share net for full-year 2012.

The Public Utilities Commission of Nevada has approved a $7 million annualized rate increase. The new rates became effective in November. However, the rate hike is much lower than the $27 million increase the company had been seeking. Including other aspects of the decision, Southwest estimates an annual operating income benefit of around $11.4 million. The company also identified several items it may request to have formally reconsidered by the commission. Southwest's focus on this matter is to be expected, as it depends on approved revenue increases to help it cope with higher costs and as compensation for infrastructure investment.

Performance may well continue to improve in 2013. The utility business should benefit from modest customer growth and recently granted rate relief. Meantime, the construction services subsidiary should continue to experience healthy demand, given the need to replace aging infrastructure.

The stock is not without risk. The company will probably incur greater operating expenses as it continues to expand. Moreover, lagging rate relief or unfavorable temperature variations could hurt the performance of the utility business.

This stock is now neutrally ranked for Timeliness. But the shares have some positive characteristics. Namely, Southwest Gas earns good marks for Price Stability and Earnings Predictability. Dividend growth ought to continue, as well, though the yield will probably remain below the industry average. Even so, this stock has decent total return potential for the coming years.

Michael Napoli, CFA *December 7, 2012*

(A) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Next egs. report due late February. (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	90
Earnings Predictability	75

WGL HOLDINGS NYSE-WGL

RECENT PRICE	37.81	P/E RATIO	14.8 (Trailing: 14.1 Median: 15.0)	RELATIVE P/E RATIO	1.00	DIV'D YLD	4.2%	VALUE LINE

TIMELINESS 3 Raised 9/9/11

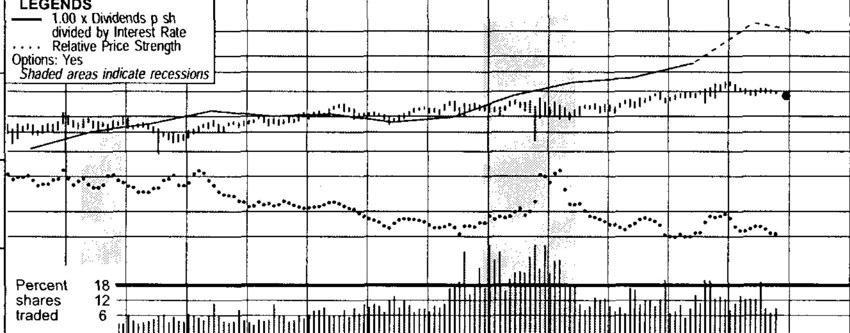
SAFETY 1 Raised 4/2/93

TECHNICAL 2 Raised 11/2/12

BETA .65 (1.00 = Market)

High:	30.5	29.5	28.8	31.4	34.8	33.6	35.9	37.1	35.5	40.0	45.0	45.0
Low:	25.3	19.3	23.2	26.7	28.8	27.0	29.8	22.4	28.6	31.0	34.7	36.0

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



Target Price Range

2015	2016	2017

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	8%
Low	35	(-5%)	3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	3	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	88	81	86
to Sell	80	96	83
Hld's(000)	31882	31569	31990

Percent shares traded 18 12 6

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.4	10.8
3 yr.	35.8	48.5
5 yr.	44.8	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
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	53.98	53.60	53.75	*47.09*	*51.20*	Revenues per sh A	*55.70*
2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.11	4.01	*4.60*	*4.40*	"Cash Flow" per sh	*4.65*
1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.09	2.44	2.53	2.27	2.25	2.68	*2.50*	Earnings per sh B	*2.75*
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	1.47	1.50	1.55	1.59	*1.63*	Div'ds Decl'd per sh C■	*1.75*
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	2.77	2.57	3.94	*5.85*	*4.85*	Cap'l Spending per sh	*4.80*
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	21.89	22.82	23.49	*24.75*	*25.55*	Book Value per sh D	*28.65*
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	50.14	50.54	51.20	*51.50*	*51.75*	Common Shs Outst'g E	*52.00*
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	12.6	15.1	17.0	15.3		Avg Ann'l P/E Ratio	*15.0*
.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.83	.82	.84	.96	1.07	.99		Relative P/E Ratio	*1.00*
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%	4.6%	4.4%	4.1%	4.3%		Avg Ann'l Div'd Yield	*4.1%*
						1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	2706.9	2708.9	2751.5	2425.3	*2650*	Revenues ($mill) A	*2895*
						55.7	112.3	98.0	104.8	96.0	102.9	122.9	128.7	115.0	115.5	*138.3*	*130*	Net Profit ($mill)	*145*
						34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	39.1%	38.7%	42.4%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
						3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	4.8%	4.2%	4.2%	*5.7%*	*4.9%*	Net Profit Margin	*5.0%*
						45.7%	43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	33.3%	33.4%	32.3%	*31.0%*	*30.5%*	Long-Term Debt Ratio	*28.5%*
						52.4%	54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	65.0%	65.0%	66.2%	*67.5%*	*68.0%*	Common Equity Ratio	*70.5%*
						1462.5	1454.9	1443.6	1478.1	1526.1	1625.4	1679.5	1687.7	1774.4	1818.1	1886.9	*1945*	Total Capital ($mill)	*2115*
						1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	2269.1	2346.2	2489.9	2667.4	*2855*	Net Plant ($mill)	*3515*
						5.3%	9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	8.8%	7.6%	7.5%	8.3%	*7.5%*	Return on Total Cap'l	*7.5%*
						7.0%	13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	11.4%	9.7%	9.4%	*10.9%*	*10.0%*	Return on Shr. Equity	*9.5%*
						7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	*11.0%*	*10.0%*	Return on Com Equity	*9.5%*
						NMF	6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	5.0%	3.3%	3.4%	4.3%	*3.5%*	Retained to Com Eq	*3.5%*
						112%	56%	65%	62%	69%	66%	57%	57%	67%	64%	59%	*65%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $836.9 mill. **Due in 5 Yrs** $112.0 mill.
LT Debt $589.2 mill. **LT Interest** $36.4 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x)

Pension Assets-9/12 $1,108.9 mill. **Oblig.** $1,417.2 mill.
Preferred Stock $28.2 mill. **Pfd. Div'd** $1.3 mill.

Common Stock 51,613,381 shs. **as of 10/31/12**

MARKET CAP: $2.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	8.9	4.3	10.3
Other	708.4	720.4	822.5
Current Assets	717.3	724.7	832.8
Accts Payable	225.4	279.4	270.4
Debt Due	130.5	116.5	247.7
Other	188.2	180.8	238.9
Current Liab.	544.1	576.7	757.0
Fix. Chg. Cov.	536%	535%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	8.5%	2.5%	.5%
"Cash Flow"	3.0%	1.5%	1.5%
Earnings	3.0%	3.0%	2.5%
Dividends	2.0%	2.5%	2.5%
Book Value	4.0%	5.0%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	826.2	1040.9	427.0	412.8	2706.9
2010	727.4	1056.6	459.7	465.2	2708.9
2011	795.9	1017.2	490.3	448.1	2751.5
2012	727.8	839.4	438.3	419.8	2425.3
2013	*785*	*895*	*495*	*475*	*2650*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1.03	1.65	.11	d.25	2.53
2010	1.01	1.64	d.07	d.29	2.27
2011	1.02	1.53	d.03	d.26	2.25
2012	1.13	1.58	.08	d.10	2.68
2013	*1.08*	*1.54*	*.03*	*d.15*	*2.50*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.34	.36	.36	.36	1.42
2009	.36	.37	.37	.37	1.47
2010	.37	.378	.378	.378	1.50
2011	.378	.39	.39	.39	1.55
2012	.39	.40	.40	.40	

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 (1,082,983 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. Black Rock Inc. owns 7.4% of common stock; Off./dir. less than 1% (1/12 proxy). Chrmn. & CEO: Terry D. McCallister. Inc.: D.C. and VA. Addr.: 101 Const. Ave., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings posted a mixed bag of financial results for fiscal 2012 (ended September 30th). Revenues declined approximately 12% due to similar downturns at both the utility and nonutility divisions. This largely reflected lower natural gas prices on a year-over-year basis. Nonetheless, this was offset by a tight handle on costs, which helped to reduce operating expenses by 210 basis points as a function of the top line. Consequently, the annual bottom line advanced 19%, to $2.68 for the year, supported by solid contributions at the Regulated Utility, Retail Energy-Marketing, and Commercial Energy Systems units.

However, this year's prospects do not appear to be as bright. Indeed, WGL's management recently released its 2013 earnings guidance of $2.37 to $2.49 per share. This has prompted us to trim a dime off our estimates for this time frame, to $2.50, a move that would represent an annual declined of almost 7%. The bulk of this downturn will likely stem from rising costs for operations & maintenance and employee pension & post retirement benefits. Too, accelerated expenses for pipeline integrity and compliance will also be a detractor this year. And an active capital expenditures pipeline adds to the margin compression. Indeed, WGL has plans for approximately $1.8 billion in growth projects through 2017. However, it is important to note that many of this year's higher costs will be recouped through rate cases down the road, and the diminished bottom line is more of an issue with the timing of expenses, rather than a breakdown in the fundamentals of the company's business. That said, WGL Holdings is expecting to add about 10,500 customer meters this year, and is actively expanding its alternative energy division.

Our Timeliness Ranking System pegs these shares to mirror the broader market averages in the coming six to 12 months. Over that time frame, WGL may appeal to investors with an eye on income generation. In fact, the yield here is above the average of the natural gas utilities group. However, on the downside, capital appreciation potential for the pull to 2015-2017 is limited, due to the stock's steady price action.

Bryan J. Fong *December 7, 2012*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢); '08, (14¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late Jan.
(C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '11: $594.4 million, $11.56/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

ATTACHMENT C

QUOTES
Overview Quote
Real Time Quotes
Option Chain
Options Greek Montage

NEWS
Zacks Commentary
Company News

ESTIMATES
Detailed Estimates

CHART
Comparative
Interactive Chart
Price and Consensus
12 month EPS
Price & EPS Surprise
Broker Recommendations
Fundamental Charts

RESEARCH
Full Company Report
Zacks Equity Research
Earnings Announcements
Brokerage Reports
Comparison to Industry
Insiders
Brokerage Recommendations
Annual Report

FINANCIALS
Financial Overview
Income Statements
Balance Sheet
Cash flow Statements

American Water Works Co Inc: (NYSE: AWK)

ZACKS RANK: 2-BUY

$38.45 0.54 (1.42%) VOLUME 220,752 JAN 22 11:56 AM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

AMER WATER is the largest investor-owned U.S. water and wastewater utility company. With headquarters in Voorhees, N.J., the company employs nearly seven thousand dedicated professionals who provide drinking water, wastewater and other related services to approximately 15.6 million people in 32 states and Ontario, Canada.

GENERAL INFORMATION

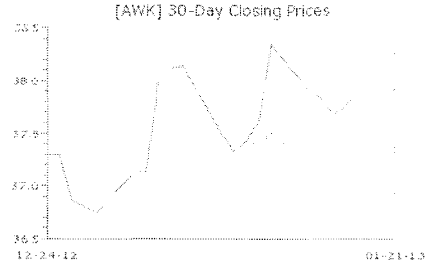
AMER WATER WORK
1025 LAUREL OAK ROAD
VOORHEES, NJ 08043
Phone: 856-346-8200
Fax: 856-346-8360
Web: http://www.amwater.com
Email: NA

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/2012
Next EPS Date	03/04/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	37.91
52 Week High	39.38
52 Week Low	32.21
Beta	0.31
20 Day Moving Average	716,080.25
Target Price Consensus	42.15

[AWK] 30-Day Closing Prices



% Price Change

4 Week	1.66
12 Week	3.41
YTD	2.10

% Price Change Relative to S&P 500

4 Week	-2.40
12 Week	-1.74
YTD	-2.01

Share Information

Shares Outstanding (millions)	176.76
Market Capitalization (millions)	6,700.86
Short Ratio	1.43
Last Split Date	NA

Dividend Information

Dividend Yield	2.64%
Annual Dividend	$1.00
Payout Ratio	0.47
Change in Payout Ratio	NA
Last Dividend Payout / Amount	12/18/2012 / $0.50

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.40

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	1.31

View the Archive

Current Year EPS Consensus Estimate	2.19	30 Days Ago	1.31
Estimated Long-Term EPS Growth Rate	8.50	60 Days Ago	1.29
Next EPS Report Date	03/04/2013	90 Days Ago	1.29

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	17.14
Trailing 12 Months	17.63
PEG Ratio	2.02

EPS Growth

vs. Previous Year	21.13%
vs. Previous Quarter	30.30%

Sales Growth

vs. Previous Year	8.53%
vs. Previous Quarter	11.56%

Price Ratios

Price/Book	1.50
Price/Cash Flow	10.10
Price / Sales	2.36

ROE

12-31-12	NA
09-30-12	8.86
06-30-12	8.28

ROA

12-31-12	NA
09-30-12	2.64
06-30-12	2.44

Current Ratio

12-31-12	NA
09-30-12	0.64
06-30-12	0.60

Quick Ratio

12-31-12	NA
09-30-12	0.61
06-30-12	0.56

Operating Margin

12-31-12	NA
09-30-12	13.48
06-30-12	12.75

Net Margin

12-31-12	NA
09-30-12	12.96
06-30-12	12.67

Pre-Tax Margin

12-31-12	NA
09-30-12	22.53
06-30-12	21.33

Book Value

12-31-12	NA
09-30-12	25.21
06-30-12	24.52

Inventory Turnover

12-31-12	NA
09-30-12	42.95
06-30-12	42.97

Debt-to-Equity

12-31-12	NA
09-30-12	1.17
06-30-12	1.21

Debt to Capital

12-31-12	NA
09-30-12	53.91
06-30-12	54.69

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American Sts Wtr Co: (NYSE: AWR)

ZACKS RANK: 3-HOLD

$51.16 0.41 (0.81%) **VOLUME 23,119** **JAN 22 11:56 AM ET**

Full Company Report Get Full Company Report for: Enter Symbol GO

American States is a public utility company engaged principally in the purchase, production, distribution and sale of water. The company also distributes 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.

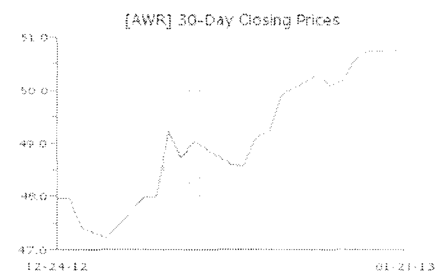
GENERAL INFORMATION

AMER STATES WTR
630 E FOOTHILL BLVD
SAN DIMAS, CA 91773-9016
Phone: 9093943600
Fax: 909-394-1382
Web: http://www.aswater.com
Email: investorinfo@aswater.com

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/2012
Next EPS Date	03/11/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	50.75
52 Week High	51.20
52 Week Low	34.90
Beta	0.34
20 Day Moving Average	76,924.05
Target Price Consensus	44.00



% Price Change

4 Week	5.80
12 Week	15.50
YTD	5.77

% Price Change Relative to S&P 500

4 Week	1.57
12 Week	9.74
YTD	1.52

Share Information

Shares Outstanding (millions)	19.22
Market Capitalization (millions)	975.21
Short Ratio	6.61
Last Split Date	06/10/02

Dividend Information

Dividend Yield	2.80%
Annual Dividend	$1.42
Payout Ratio	0.54
Change in Payout Ratio	NA
Last Dividend Payout / Amount	11/07/2012 / $0.35

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.37

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.00

Current Year EPS Consensus Estimate	2.66	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	2.71
Next EPS Report Date	03/11/2013	90 Days Ago	2.71

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	18.74
Trailing 12 Months	19.22
PEG Ratio	3.12

EPS Growth

vs. Previous Year	16.87%
vs. Previous Quarter	22.78%

Sales Growth

vs. Previous Year	11.36%
vs. Previous Quarter	16.81%

Price Ratios

Price/Book	2.14
Price/Cash Flow	11.83
Price / Sales	2.17

ROE

12-31-12	NA
09-30-12	11.90
06-30-12	11.48

ROA

12-31-12	NA
09-30-12	4.02
06-30-12	3.85

Current Ratio

12-31-12	NA
09-30-12	1.71
06-30-12	1.77

Quick Ratio

12-31-12	NA
09-30-12	1.65
06-30-12	1.72

Operating Margin

12-31-12	NA
09-30-12	11.24
06-30-12	10.90

Net Margin

12-31-12	NA
09-30-12	11.24
06-30-12	10.89

Pre-Tax Margin

12-31-12	NA
09-30-12	18.89
06-30-12	18.37

Book Value

12-31-12	NA
09-30-12	23.72
06-30-12	22.64

Inventory Turnover

12-31-12	NA
09-30-12	21.38
06-30-12	25.88

Debt-to-Equity

12-31-12	NA
09-30-12	0.77
06-30-12	0.80

Debt to Capital

12-31-12	NA
09-30-12	43.40
06-30-12	44.44

California Wtr Svc Group: (NYSE: CWT)

ZACKS RANK: 1-STRONG BUY

$19.30 0.14 (0.73%) VOLUME 130,256 JAN 22 11:58 AM ET

Full Company Report

Get Full Company Report for: Enter Symbol GO

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.

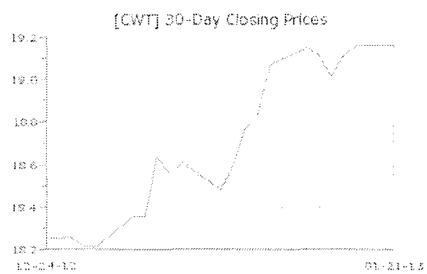
GENERAL INFORMATION

CALIF WATER SVC
1720 N FIRST ST C/O CALIFORNIA WATER SERVICE CO
SAN JOSE, CA 95112
Phone: 408-367-8200
Fax: 831-427-9185
Web: http://www.calwatergroup.com
Email: NA

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/2012
Next EPS Date	03/06/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	19.16
52 Week High	19.49
52 Week Low	16.84
Beta	0.27
20 Day Moving Average	149,734.09
Target Price Consensus	20.00



% Price Change

4 Week	4.99
12 Week	3.96
YTD	4.41

% Price Change Relative to S&P 500

4 Week	0.80
12 Week	-1.22
YTD	0.21

Share Information

Shares Outstanding (millions)	41.90
Market Capitalization (millions)	802.90
Short Ratio	7.24
Last Split Date	06/13/11

Dividend Information

Dividend Yield	3.29%
Annual Dividend	$0.63
Payout Ratio	0.59
Change in Payout Ratio	NA
Last Dividend Payout / Amount	11/07/2012 / $0.16

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.09

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.38

Current Year EPS Consensus Estimate	0.98	30 Days Ago	2.38
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	2.57
Next EPS Report Date	03/06/2013	90 Days Ago	2.38

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	18.60
Trailing 12 Months	18.08
PEG Ratio	3.72

EPS Growth

vs. Previous Year	42.00%
vs. Previous Quarter	129.03%

Sales Growth

vs. Previous Year	5.25%
vs. Previous Quarter	24.09%

Price Ratios

Price/Book	1.69
Price/Cash Flow	9.16
Price / Sales	1.48

ROE

12-31-12	NA
09-30-12	9.84
06-30-12	7.99

ROA

12-31-12	NA
09-30-12	2.35
06-30-12	1.93

Current Ratio

12-31-12	NA
09-30-12	0.79
06-30-12	0.64

Quick Ratio

12-31-12	NA
09-30-12	0.76
06-30-12	0.61

Operating Margin

12-31-12	NA
09-30-12	8.27
06-30-12	6.75

Net Margin

12-31-12	NA
09-30-12	8.44
06-30-12	6.92

Pre-Tax Margin

12-31-12	NA
09-30-12	13.11
06-30-12	11.36

Book Value

12-31-12	NA
09-30-12	11.33
06-30-12	10.77

Inventory Turnover

12-31-12	NA
09-30-12	39.18
06-30-12	38.78

Debt-to-Equity

12-31-12	NA
09-30-12	1.01
06-30-12	1.06

Debt to Capital

12-31-12	NA
09-30-12	50.24
06-30-12	51.53

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NYSE and AMEX data is at least 20 minutes delayed. NASDAQ data is at least 15 minutes delayed.

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- Financial Overview
- Income Statements
- Balance Sheet
- Cash flow Statements

Middlesex Water Co: (NASD: MSEX)

ZACKS RANK: 3-HOLD

$19.37 0.09 (0.46%) **VOLUME 8,015** JAN 22 11:57 AM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

Middlesex Water Company treats, stores and distributes water for residential, commercial, industrial and fire prevention purposes.

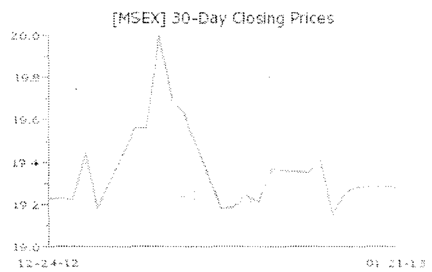
GENERAL INFORMATION

MIDDLESEX WATER
1500 RONSON RD P O BOX 1500
ISELIN, NJ 08830
Phone: 7326341500
Fax: 732-638-7515
Web: http://www.middlesexwater.com
Email: bsohler@middlesexwater.com

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/2012
Next EPS Date	03/07/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	19.28
52 Week High	20.06
52 Week Low	17.48
Beta	0.48
20 Day Moving Average	27,488.60
Target Price Consensus	20.50



% Price Change

4 Week	0.26
12 Week	0.42
YTD	-1.43

% Price Change Relative to S&P 500

4 Week	-3.74
12 Week	-4.59
YTD	-5.40

Share Information

Shares Outstanding (millions)	15.76
Market Capitalization (millions)	303.76
Short Ratio	15.41
Last Split Date	11/17/03

Dividend Information

Dividend Yield	3.89%
Annual Dividend	$0.75
Payout Ratio	0.88
Change in Payout Ratio	NA
Last Dividend Payout / Amount	11/13/2012 / $0.19

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.19
Current Year EPS Consensus Estimate	0.92

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.33
30 Days Ago	2.33

View the Archive

Estimated Long-Term EPS Growth Rate	Subscribe NA	60 Days Ago	2.33
Next EPS Report Date	03/07/2013	90 Days Ago	2.33

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FUNDAMENTAL RATIOS

P/E		EPS Growth		Sales Growth	
Current FY Estimate	17.96	vs. Previous Year	18.75%	vs. Previous Year	12.84%
Trailing 12 Months	22.95	vs. Previous Quarter	65.22%	vs. Previous Quarter	18.07%
PEG Ratio	NA				

Price Ratios		ROE		ROA	
Price/Book	1.67	12-31-12	NA	12-31-12	NA
Price/Cash Flow	12.63	09-30-12	7.67	09-30-12	2.52
Price / Sales	2.85	06-30-12	7.18	06-30-12	2.39

Current Ratio		Quick Ratio		Operating Margin	
12-31-12	NA	12-31-12	NA	12-31-12	NA
09-30-12	0.51	09-30-12	0.48	09-30-12	12.82
06-30-12	0.48	06-30-12	0.44	06-30-12	12.36

Net Margin		Pre-Tax Margin		Book Value	
12-31-12	NA	12-31-12	NA	12-31-12	NA
09-30-12	12.87	09-30-12	19.38	09-30-12	11.53
06-30-12	12.36	06-30-12	18.66	06-30-12	11.31

Inventory Turnover		Debt-to-Equity		Debt to Capital	
12-31-12	NA	12-31-12	NA	12-31-12	NA
09-30-12	31.22	09-30-12	0.73	09-30-12	41.75
06-30-12	28.62	06-30-12	0.76	06-30-12	42.72

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Visit performance for information about the performance numbers displayed above.

NYSE and AMEX data is at least 20 minutes delayed. NASDAQ data is at least 15 minutes delayed.

Sjw Corp: (NYSE: SJW)

ZACKS RANK: 4-SELL

$26.24 0.34 (1.31%) **VOLUME 12,469** **JAN 22 11:57 AM ET**

Full Company Report

Get Full Company Report for: Enter Symbol GO

SJW CORP. is a holding company which operates through its wholly-owned subsidiaries, San Jose Water Co., SJW Land Co., and Western Precision, Inc. San Jose Water Co., is a public utility in the business of providing water service to a population of approximately 928,000 people. Their service area encompasses about 134 sq. miles in the metropolitan San Juan area. SJW Land Co. operates parking facilities located adjacent to the their headquarters and the San Jose area.

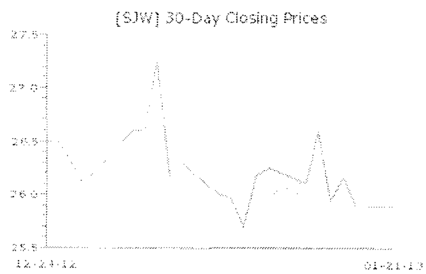
GENERAL INFORMATION

SJW CORP
110 W. TAYLOR STREET
SAN JOSE, CA 95110
Phone: 4082797800
Fax: 4082797917
Web: http://www.sjwater.com/
Email: boardofdirectors@sjwater.com

Industry	**UTIL-WATER SPLY**
Sector	**Utilities**
Fiscal Year End	**December**
Last Reported Quarter	**12/31/2012**
Next EPS Date	**02/19/2013**

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	**25.90**
52 Week High	**27.60**
52 Week Low	**22.56**
Beta	**0.61**
20 Day Moving Average	**23,450.85**
Target Price Consensus	**27.25**



% Price Change

4 Week	**-2.23**
12 Week	**7.69**
YTD	**-2.63**

% Price Change Relative to S&P 500

4 Week	**-6.13**
12 Week	**2.33**
YTD	**-6.55**

Share Information

Shares Outstanding (millions)	**18.65**
Market Capitalization (millions)	**483.14**
Short Ratio	**14.25**
Last Split Date	**03/17/06**

Dividend Information

Dividend Yield	**2.74%**
Annual Dividend	**$0.71**
Payout Ratio	**0.68**
Change in Payout Ratio	**NA**
Last Dividend Payout / Amount	**11/01/2012 / $0.18**

EPS INFORMATION

Current Quarter EPS Consensus Estimate	**0.18**

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	**1.50**

Current Year EPS Consensus Estimate	1.05	30 Days Ago	1.50
Estimated Long-Term EPS Growth Rate	NA	60 Days Ago	1.50
Next EPS Report Date	02/19/2013	90 Days Ago	1.50

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	19.36
Trailing 12 Months	24.90
PEG Ratio	NA

EPS Growth

vs. Previous Year	20.45%
vs. Previous Quarter	89.29%

Sales Growth

vs. Previous Year	11.45%
vs. Previous Quarter	25.62%

Price Ratios

Price/Book	1.78
Price/Cash Flow	9.59
Price / Sales	1.85

ROE

12-31-12	NA
09-30-12	7.40
06-30-12	6.77

ROA

12-31-12	NA
09-30-12	1.87
06-30-12	1.71

Current Ratio

12-31-12	NA
09-30-12	1.22
06-30-12	1.27

Quick Ratio

12-31-12	NA
09-30-12	1.20
06-30-12	1.25

Operating Margin

12-31-12	NA
09-30-12	7.52
06-30-12	7.03

Net Margin

12-31-12	NA
09-30-12	8.80
06-30-12	8.35

Pre-Tax Margin

12-31-12	NA
09-30-12	14.98
06-30-12	14.15

Book Value

12-31-12	NA
09-30-12	14.58
06-30-12	14.20

Inventory Turnover

12-31-12	NA
09-30-12	116.20
06-30-12	112.74

Debt-to-Equity

12-31-12	NA
09-30-12	1.24
06-30-12	1.27

Debt to Capital

12-31-12	NA
09-30-12	55.28
06-30-12	55.96

Aqua America Inc: (NYSE: WTR)

ZACKS RANK: 1-STRONG BUY

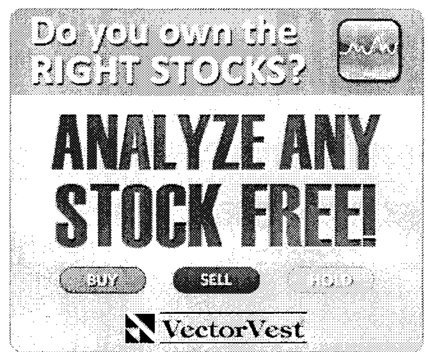
$27.06 0.19 (0.71%) **VOLUME 220,096** JAN 22 12:02 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

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

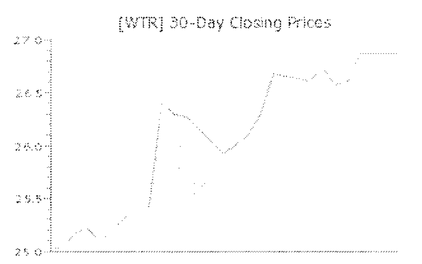
AQUA AMER INC
762 W. LANCASTER AVE
BRYN MAWR, PA 19010-3489
Phone: 2155278000
Fax: 610-645-1061
Web: http://www.aquaamerica.com
Email: NA



Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/2012
Next EPS Date	03/04/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	26.87
52 Week High	27.08
52 Week Low	21.43
Beta	0.19
20 Day Moving Average	643,485.13
Target Price Consensus	26.86



% Price Change

4 Week	7.31
12 Week	6.42
YTD	5.70

% Price Change Relative to S&P 500

4 Week	3.02
12 Week	1.11
YTD	1.45

Share Information

Shares Outstanding (millions)	139.94
Market Capitalization (millions)	3,760.22
Short Ratio	7.99
Last Split Date	12/02/05

Dividend Information

Dividend Yield	2.61%
Annual Dividend	$0.70
Payout Ratio	0.62
Change in Payout Ratio	NA
Last Dividend Payout / Amount	11/14/2012 / $0.17

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.24

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.46

Current Year EPS Consensus Estimate	1.09	30 Days Ago	2.46
Estimated Long-Term EPS Growth Rate	6.90	60 Days Ago	2.46
Next EPS Report Date	03/04/2013	90 Days Ago	2.54

FUNDAMENTAL RATIOS

P/E		EPS Growth		Sales Growth	
Current FY Estimate	22.52	vs. Previous Year	20.00%	vs. Previous Year	8.74%
Trailing 12 Months	25.35	vs. Previous Quarter	20.00%	vs. Previous Quarter	8.25%
PEG Ratio	3.28				

Price Ratios		ROE		ROA	
Price/Book	2.86	12-31-12	NA	12-31-12	NA
Price/Cash Flow	15.39	09-30-12	11.59	09-30-12	3.39
Price / Sales	4.98	06-30-12	11.17	06-30-12	3.25

Current Ratio		Quick Ratio		Operating Margin	
12-31-12	NA	12-31-12	NA	12-31-12	NA
09-30-12	0.73	09-30-12	0.69	09-30-12	19.71
06-30-12	0.69	06-30-12	0.64	06-30-12	19.07

Net Margin		Pre-Tax Margin		Book Value	
12-31-12	NA	12-31-12	NA	12-31-12	NA
09-30-12	21.70	09-30-12	32.65	09-30-12	9.41
06-30-12	20.92	06-30-12	31.56	06-30-12	9.37

Inventory Turnover		Debt-to-Equity		Debt to Capital	
12-31-12	NA	12-31-12	NA	12-31-12	NA
09-30-12	24.36	09-30-12	1.16	09-30-12	53.61
06-30-12	24.24	06-30-12	1.20	06-30-12	54.65

Agl Resources Inc: (NYSE: GAS)

ZACKS RANK: 3-HOLD

$41.34 0.18 (0.44%) **VOLUME 128,324** **JAN 22 12:02 PM ET**

Full Company Report

Get Full Company Report for: Enter Symbol GO

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.

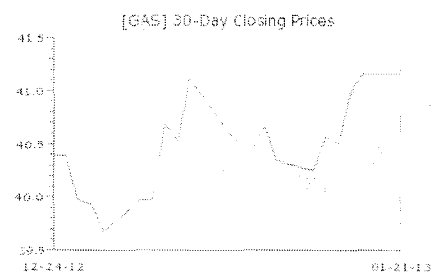
GENERAL INFORMATION

AGL RESOURCES
TEN PEACHTREE PLACE
ATLANTA, GA 30309
Phone: 4045844000
Fax: 404-584-3714
Web: http://www.aglresources.com
Email: sstashak@aglresources.com

Industry	**UTIL-GAS DISTR**
Sector	**Utilities**
Fiscal Year End	**December**
Last Reported Quarter	**12/31/2012**
Next EPS Date	**02/06/2013**

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	41.16
52 Week High	42.34
52 Week Low	36.59
Beta	0.41
20 Day Moving Average	357,076.41
Target Price Consensus	41.40



% Price Change

4 Week	1.91
12 Week	2.18
YTD	2.98

% Price Change Relative to S&P 500

4 Week	-2.16
12 Week	-2.91
YTD	-1.17

Share Information

Shares Outstanding (millions)	117.78
Market Capitalization (millions)	4,847.91
Short Ratio	2.92
Last Split Date	12/04/95

Dividend Information

Dividend Yield	**4.47%**
Annual Dividend	**$1.84**
Payout Ratio	**0.76**
Change in Payout Ratio	**NA**
Last Dividend Payout / Amount	**11/14/2012 / $0.46**

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.07

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.57

Current Year EPS Consensus Estimate	2.65	30 Days Ago	2.57
Estimated Long-Term EPS Growth Rate	4.40	60 Days Ago	2.57
Next EPS Report Date	02/06/2013	90 Days Ago	2.57

FUNDAMENTAL RATIOS

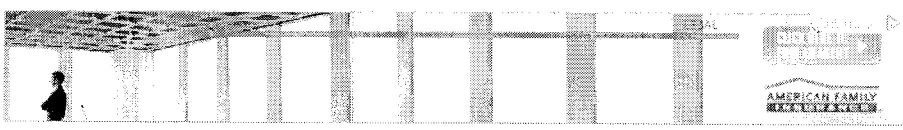
P/E		EPS Growth		Sales Growth	
Current FY Estimate	13.73	vs. Previous Year	350.00%	vs. Previous Year	108.14%
Trailing 12 Months	17.01	vs. Previous Quarter	-70.00%	vs. Previous Quarter	-10.50%
PEG Ratio	3.12				

Price Ratios		ROE		ROA	
Price/Book	1.42	12-31-12	NA	12-31-12	NA
Price/Cash Flow	7.74	09-30-12	7.63	09-30-12	1.92
Price / Sales	1.39	06-30-12	8.31	06-30-12	2.09

Current Ratio		Quick Ratio		Operating Margin	
12-31-12	NA	12-31-12	NA	12-31-12	NA
09-30-12	0.77	09-30-12	0.49	09-30-12	7.42
06-30-12	0.76	06-30-12	0.54	06-30-12	7.90

Net Margin		Pre-Tax Margin		Book Value	
12-31-12	NA	12-31-12	NA	12-31-12	NA
09-30-12	5.90	09-30-12	10.48	09-30-12	28.92
06-30-12	6.11	06-30-12	10.87	06-30-12	29.23

Inventory Turnover		Debt-to-Equity		Debt to Capital	
12-31-12	NA	12-31-12	NA	12-31-12	NA
09-30-12	3.76	09-30-12	0.98	09-30-12	49.49
06-30-12	3.63	06-30-12	0.97	06-30-12	49.30



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At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1986 it has nearly tripled the S&P 500 with an average gain of +26% per year. These returns cover a period from 1986-2011 and were examined and attested by Baker Tilly, an independent accounting firm.

Visit performance for information about the performance numbers displayed above.

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Cash flow Statements

Atmos Energy Corp: (NYSE: ATO)

ZACKS RANK: 4-SELL

$37.51 0.53 (1.43%) **VOLUME 209,986** JAN 22 12:03 PM ET

Full Company Report

Get Full Company Report for: Enter Symbol GO

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.

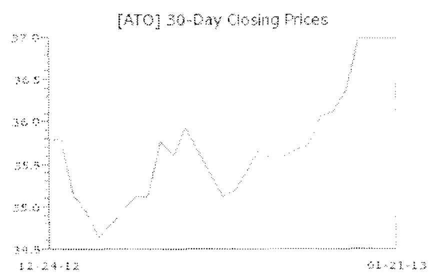
GENERAL INFORMATION

ATMOS ENERGY CP
1800 THREE LINCOLN CTR 5430 LBJ FREEWAY
DALLAS, TX 75240
Phone: 9729349227
Fax: 972-855-3040
Web: http://www.atmosenergy.com
Email: NA

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	September
Last Reported Quarter	12/31/2012
Next EPS Date	02/06/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	36.98
52 Week High	37.57
52 Week Low	30.39
Beta	0.45
20 Day Moving Average	364,562.41
Target Price Consensus	36.80



% Price Change

4 Week	3.35
12 Week	3.30
YTD	5.30

% Price Change Relative to S&P 500

4 Week	-0.77
12 Week	-1.85
YTD	1.06

Share Information

Shares Outstanding (millions)	90.46
Market Capitalization (millions)	3,345.28
Short Ratio	3.60
Last Split Date	05/17/94

Dividend Information

Dividend Yield	3.79%
Annual Dividend	$1.40
Payout Ratio	0.59
Change in Payout Ratio	NA
Last Dividend Payout / Amount	11/21/2012 / $0.35

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EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.78
Current Year EPS Consensus Estimate	2.43
Estimated Long-Term EPS Growth Rate	6.00
Next EPS Report Date	02/06/2013

CONSENSUS RECOMMENDATIONS

Sub

Current (1=Strong Buy, 5=Strong Sell)	2.57
30 Days Ago	2.57
60 Days Ago	2.57
90 Days Ago	2.57

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	15.23
Trailing 12 Months	15.74
PEG Ratio	2.54

EPS Growth

vs. Previous Year	133.33%
vs. Previous Quarter	-56.25%

Sales Growth

vs. Previous Year	-30.22%
vs. Previous Quarter	-13.28%

Price Ratios

Price/Book	1.41
Price/Cash Flow	7.13
Price / Sales	0.97

ROE

12-31-12	NA
09-30-12	9.15
06-30-12	8.97

ROA

12-31-12	NA
09-30-12	2.86
06-30-12	2.80

Current Ratio

12-31-12	NA
09-30-12	0.65
06-30-12	0.70

Quick Ratio

12-31-12	NA
09-30-12	0.45
06-30-12	0.48

Operating Margin

12-31-12	NA
09-30-12	6.22
06-30-12	5.66

Net Margin

12-31-12	NA
09-30-12	6.30
06-30-12	5.76

Pre-Tax Margin

12-31-12	NA
09-30-12	8.45
06-30-12	8.52

Book Value

12-31-12	NA
09-30-12	26.16
06-30-12	26.16

Inventory Turnover

12-31-12	NA
09-30-12	9.85
06-30-12	10.35

Debt-to-Equity

12-31-12	NA
09-30-12	0.83
06-30-12	0.83

Debt to Capital

12-31-12	NA
09-30-12	45.33
06-30-12	45.38

At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1986 it has nearly tripled the S&P 500 with an average gain of +26% per year. These returns cover a period from 1986-2011 and were examined and attested by Baker Tilly, an independent accounting firm.

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Balance Sheet
Cash flow Statements

Laclede Group Inc: (NYSE: LG)

ZACKS RANK: 3-HOLD

$39.22 0.22 (0.56%) **VOLUME 16,672** JAN 22 11:57 AM ET

Full Company Report

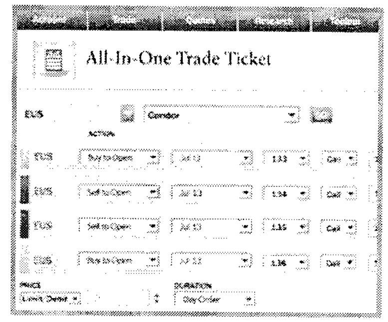
Get Full Company Report for: Enter Symbol GO

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

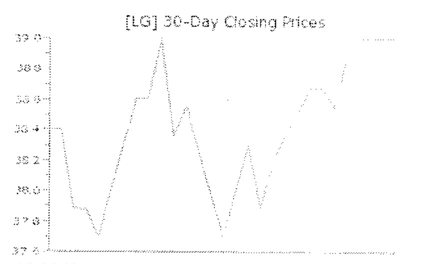
LACLEDE GRP INC
720 OLIVE ST
ST LOUIS, MO 63101
Phone: 3143420500
Fax: 3144211979
Web: http://www.thelacledegroup.com
Email: mkullman@lacledegas.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	September
Last Reported Quarter	12/31/2012
Next EPS Date	02/05/2013



PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	39.00
52 Week High	44.04
52 Week Low	36.53
Beta	0.06
20 Day Moving Average	107,995.35
Target Price Consensus	42.50



% Price Change

4 Week	1.56
12 Week	-6.45
YTD	1.01

% Price Change Relative to S&P 500

4 Week	-2.49
12 Week	-11.11
YTD	-3.05

Share Information

Shares Outstanding (millions)	22.53
Market Capitalization (millions)	878.55
Short Ratio	11.31
Last Split Date	03/08/94

Dividend Information

Dividend Yield	4.36%
Annual Dividend	$1.70
Payout Ratio	0.59
Change in Payout Ratio	NA
Last Dividend Payout / Amount	12/07/2012 / $0.43

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.09

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.00

Current Year EPS Consensus Estimate	2.79	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	3.00	60 Days Ago	3.00
Next EPS Report Date	02/05/2013	90 Days Ago	3.00

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	13.99
Trailing 12 Months	13.93
PEG Ratio	4.66

EPS Growth

vs. Previous Year	114.29%
vs. Previous Quarter	-95.00%

Sales Growth

vs. Previous Year	-37.45%
vs. Previous Quarter	-9.26%

Price Ratios

Price/Book	1.46
Price/Cash Flow	8.44
Price / Sales	0.78

ROE

12-31-12	NA
09-30-12	10.36
06-30-12	9.89

ROA

12-31-12	NA
09-30-12	3.45
06-30-12	3.30

Current Ratio

12-31-12	NA
09-30-12	1.36
06-30-12	1.46

Quick Ratio

12-31-12	NA
09-30-12	0.94
06-30-12	1.07

Operating Margin

12-31-12	NA
09-30-12	5.57
06-30-12	4.81

Net Margin

12-31-12	NA
09-30-12	5.57
06-30-12	4.93

Pre-Tax Margin

12-31-12	NA
09-30-12	7.90
06-30-12	7.09

Book Value

12-31-12	NA
09-30-12	26.73
06-30-12	27.18

Inventory Turnover

12-31-12	NA
09-30-12	8.28
06-30-12	8.85

Debt-to-Equity

12-31-12	NA
09-30-12	0.56
06-30-12	0.56

Debt to Capital

12-31-12	NA
09-30-12	36.07
06-30-12	35.71

New Jersey Resources Corp: (NYSE: NJR)

ZACKS RANK: 5-STRONG SELL

$41.23 0.14 (0.34%) **VOLUME 44,111** **JAN 22 12:02 PM ET**

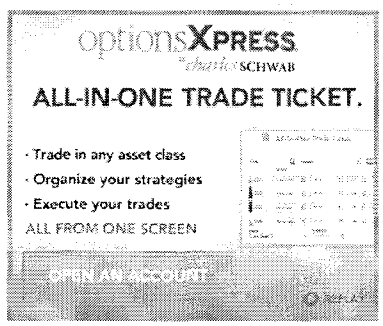
Full Company Report

Get Full Company Report for: Enter Symbol GO

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

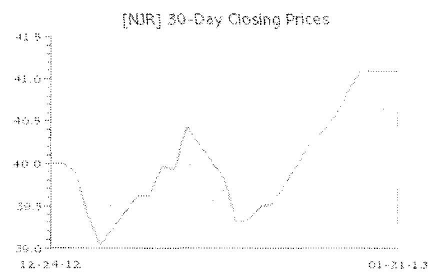
NJ RESOURCES
1415 WYCKOFF RD PO BOX 1468
WALL, NJ 07719
Phone: 9089381494
Fax: 732-938-2134
Web: http://www.njresources.com
Email: dpuma@njresources.com



Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	September
Last Reported Quarter	12/31/2012
Next EPS Date	02/05/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	41.09
52 Week High	49.66
52 Week Low	38.51
Beta	0.23
20 Day Moving Average	207,356.66
Target Price Consensus	43.60



% Price Change

4 Week	2.72
12 Week	-7.87
YTD	3.71

% Price Change Relative to S&P 500

4 Week	-1.38
12 Week	-12.46
YTD	-0.46

Share Information

Shares Outstanding (millions)	41.69
Market Capitalization (millions)	1,713.00
Short Ratio	9.42
Last Split Date	03/04/08

Dividend Information

Dividend Yield	3.89%
Annual Dividend	$1.60
Payout Ratio	0.59
Change in Payout Ratio	NA
Last Dividend Payout / Amount	12/12/2012 / $0.40

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.00
Current Year EPS Consensus Estimate	2.47
Estimated Long-Term EPS Growth Rate	4.00
Next EPS Report Date	02/05/2013

CONSENSUS RECOMMENDATIONS

Sub

Current (1=Strong Buy, 5=Strong Sell)	3.14
30 Days Ago	3.14
60 Days Ago	3.14
90 Days Ago	3.14

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	16.65
Trailing 12 Months	15.16
PEG Ratio	4.16

EPS Growth

vs. Previous Year	-1,450.00%
vs. Previous Quarter	-370.00%

Sales Growth

vs. Previous Year	-15.27%
vs. Previous Quarter	33.72%

Price Ratios

Price/Book	2.10
Price/Cash Flow	11.09
Price / Sales	0.76

ROE

12-31-12	NA
09-30-12	13.49
06-30-12	15.08

ROA

12-31-12	NA
09-30-12	4.10
06-30-12	4.58

Current Ratio

12-31-12	NA
09-30-12	0.99
06-30-12	0.99

Quick Ratio

12-31-12	NA
09-30-12	0.57
06-30-12	0.65

Operating Margin

12-31-12	NA
09-30-12	5.00
06-30-12	5.28

Net Margin

12-31-12	NA
09-30-12	4.13
06-30-12	4.00

Pre-Tax Margin

12-31-12	NA
09-30-12	4.00
06-30-12	3.76

Book Value

12-31-12	NA
09-30-12	19.57
06-30-12	20.12

Inventory Turnover

12-31-12	NA
09-30-12	8.22
06-30-12	8.41

Debt-to-Equity

12-31-12	NA
09-30-12	0.65
06-30-12	0.51

Debt to Capital

12-31-12	NA
09-30-12	39.22
06-30-12	33.86

Northwest Natural Gas: (NYSE: NWN)

ZACKS RANK: 3-HOLD

$44.43 0.50 (1.14%) **VOLUME 39,207** **JAN 22 12:03 PM ET**

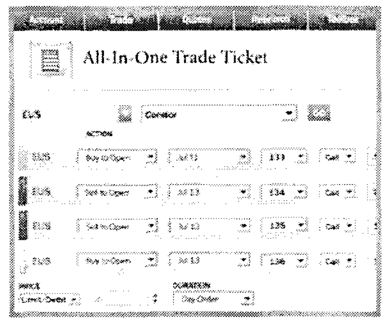
Full Company Report

Get Full Company Report for: Enter Symbol GO

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

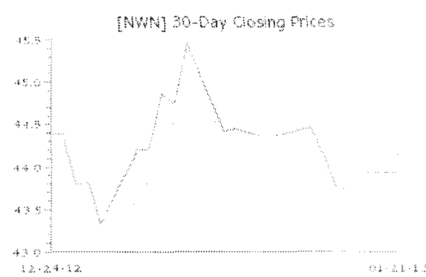
NORTHWEST NAT G
ONE PACIFIC SQUARE 220 NW SECOND AVE
PORTLAND, OR 97209
Phone: 5032264211
Fax: 503-273-4824
Web: http://www.nwnatural.com
Email: bob.hess@nwnatural.com



Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/2012
Next EPS Date	03/01/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	43.93
52 Week High	50.80
52 Week Low	41.01
Beta	0.26
20 Day Moving Average	96,291.35
Target Price Consensus	45.25



% Price Change

4 Week	-1.04
12 Week	-8.06
YTD	-0.61

% Price Change Relative to S&P 500

4 Week	-4.99
12 Week	-12.64
YTD	-4.61

Share Information

Shares Outstanding (millions)	26.87
Market Capitalization (millions)	1,180.57
Short Ratio	15.00
Last Split Date	09/09/96

Dividend Information

Dividend Yield	4.14%
Annual Dividend	$1.82
Payout Ratio	0.75
Change in Payout Ratio	NA
Last Dividend Payout / Amount	10/29/2012 / $0.46

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EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.10
Current Year EPS Consensus Estimate	2.37
Estimated Long-Term EPS Growth Rate	4.20
Next EPS Report Date	03/01/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.13
30 Days Ago	3.13
60 Days Ago	3.13
90 Days Ago	2.88

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	17.52
Trailing 12 Months	18.61
PEG Ratio	4.21

EPS Growth

vs. Previous Year	6.45%
vs. Previous Quarter	-680.00%

Sales Growth

vs. Previous Year	-3.81%
vs. Previous Quarter	-15.78%

Price Ratios

Price/Book	1.64
Price/Cash Flow	8.48
Price / Sales	1.50

ROE

12-31-12	NA
09-30-12	8.70
06-30-12	8.70

ROA

12-31-12	NA
09-30-12	2.35
06-30-12	2.36

Current Ratio

12-31-12	NA
09-30-12	0.57
06-30-12	0.71

Quick Ratio

12-31-12	NA
09-30-12	0.36
06-30-12	0.45

Operating Margin

12-31-12	NA
09-30-12	8.08
06-30-12	7.98

Net Margin

12-31-12	NA
09-30-12	7.73
06-30-12	7.98

Pre-Tax Margin

12-31-12	NA
09-30-12	13.55
06-30-12	13.43

Book Value

12-31-12	NA
09-30-12	26.74
06-30-12	27.52

Inventory Turnover

12-31-12	NA
09-30-12	7.45
06-30-12	7.25

Debt-to-Equity

12-31-12	NA
09-30-12	0.89
06-30-12	0.87

Debt to Capital

12-31-12	NA
09-30-12	47.21
06-30-12	46.53

Piedmont Natural Gas Co Inc: (NYSE: PNY)

ZACKS RANK: 3-HOLD

$32.60 -0.10 (-0.31%) VOLUME 130,839 JAN 22 12:06 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

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.

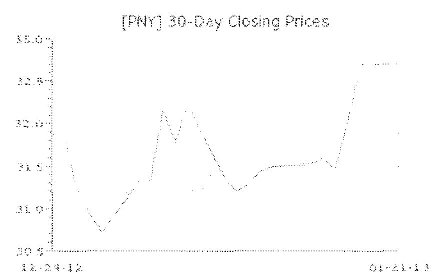
GENERAL INFORMATION

PIEDMONT NAT GA
4720 PIEDMONT ROW DR
CHARLOTTE, NC 28233
Phone: 7043643120
Fax: 704-365-3849
Web: http://www.piedmontng.com
Email: investorrelations@piedmontng.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	October
Last Reported Quarter	10/31/2012
Next EPS Date	03/08/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	32.70
52 Week High	34.00
52 Week Low	28.51
Beta	0.30
20 Day Moving Average	333,477.69
Target Price Consensus	31.80



% Price Change

4 Week	2.57
12 Week	3.58
YTD	4.44

% Price Change Relative to S&P 500

4 Week	-1.52
12 Week	-1.58
YTD	0.24

Share Information

Shares Outstanding (millions)	72.28
Market Capitalization (millions)	2,363.43
Short Ratio	15.69
Last Split Date	11/01/04

Dividend Information

Dividend Yield	3.67%
Annual Dividend	$1.20
Payout Ratio	0.72
Change in Payout Ratio	0.01
Last Dividend Payout / Amount	12/20/2012 / $0.30

EPS INFORMATION

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Current Quarter EPS Consensus Estimate	1.15
Current Year EPS Consensus Estimate	1.74
Estimated Long-Term EPS Growth Rate	3.70
Next EPS Report Date	03/08/2013

CONSENSUS RECOMMENDATIONS

Sub

Current (1=Strong Buy, 5=Strong Sell)	3.00
30 Days Ago	3.14
60 Days Ago	3.14
90 Days Ago	3.29

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	18.81
Trailing 12 Months	19.70
PEG Ratio	5.04

EPS Growth

vs. Previous Year	76.92%
vs. Previous Quarter	50.00%

Sales Growth

vs. Previous Year	-5.53%
vs. Previous Quarter	12.58%

Price Ratios

Price/Book	2.29
Price/Cash Flow	10.30
Price / Sales	2.10

ROE

10-31-12	11.51
07-31-12	10.85
04-30-12	10.51

ROA

10-31-12	3.37
07-31-12	3.28
04-30-12	3.24

Current Ratio

10-31-12	0.52
07-31-12	0.73
04-30-12	0.99

Quick Ratio

10-31-12	0.39
07-31-12	0.54
04-30-12	0.72

Operating Margin

10-31-12	10.67
07-31-12	9.90
04-30-12	9.25

Net Margin

10-31-12	10.67
07-31-12	9.90
04-30-12	9.25

Pre-Tax Margin

10-31-12	17.64
07-31-12	16.29
04-30-12	15.12

Book Value

10-31-12	14.25
07-31-12	14.53
04-30-12	14.85

Inventory Turnover

10-31-12	9.65
07-31-12	9.31
04-30-12	9.15

Debt-to-Equity

10-31-12	0.95
07-31-12	0.93
04-30-12	0.92

Debt to Capital

10-31-12	48.70
07-31-12	48.27
04-30-12	47.80

QUOTES
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NEWS
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Company News

ESTIMATES
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CHART
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RESEARCH
Full Company Report
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Annual Report

FINANCIALS
Financial Overview
Income Statements
Balance Sheet
Cash flow Statements

South Jersey Industries Inc: (NYSE: SJI)

ZACKS RANK: 3-HOLD

$53.28 0.44 (0.83%) **VOLUME 17,657** JAN 22 12:03 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

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.

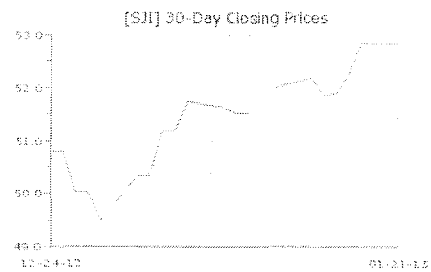
GENERAL INFORMATION

SOUTH JERSEY IN
1 SOUTH JERSEY PLAZA ROUTE 54
FOLSOM, NJ 08037
Phone: 609-561-9000
Fax: 609-561-8225
Web: http://www.sjindustries.com
Email: NA

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/2012
Next EPS Date	03/05/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	52.84
52 Week High	56.15
52 Week Low	45.81
Beta	0.31
20 Day Moving Average	118,145.05
Target Price Consensus	61.00



% Price Change

4 Week	4.00
12 Week	3.65
YTD	4.99

% Price Change Relative to S&P 500

4 Week	-0.16
12 Week	-1.52
YTD	0.76

Share Information

Shares Outstanding (millions)	31.26
Market Capitalization (millions)	1,651.94
Short Ratio	8.85
Last Split Date	07/01/05

Dividend Information

Dividend Yield	3.35%
Annual Dividend	$1.77
Payout Ratio	0.52
Change in Payout Ratio	NA
Last Dividend Payout / Amount	12/06/2012 / $0.44

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.06

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	1.50

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Current Year EPS Consensus Estimate		30 Days Ago	1.50
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	1.50
Next EPS Report Date	03/05/2013	90 Days Ago	1.50

Sub

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	15.74
Trailing 12 Months	16.99
PEG Ratio	2.62

EPS Growth

vs. Previous Year	1,200.00%
vs. Previous Quarter	-53.57%

Sales Growth

vs. Previous Year	-18.63%
vs. Previous Quarter	-8.15%

Price Ratios

Price/Book	2.34
Price/Cash Flow	11.82
Price / Sales	2.34

ROE

12-31-12	NA
09-30-12	14.21
06-30-12	14.20

ROA

12-31-12	NA
09-30-12	4.09
06-30-12	4.08

Current Ratio

12-31-12	NA
09-30-12	0.59
06-30-12	0.57

Quick Ratio

12-31-12	NA
09-30-12	0.47
06-30-12	0.47

Operating Margin

12-31-12	NA
09-30-12	13.36
06-30-12	12.40

Net Margin

12-31-12	NA
09-30-12	14.61
06-30-12	13.12

Pre-Tax Margin

12-31-12	NA
09-30-12	16.58
06-30-12	14.75

Book Value

12-31-12	NA
09-30-12	22.54
06-30-12	22.13

Inventory Turnover

12-31-12	NA
09-30-12	9.00
06-30-12	9.06

Debt-to-Equity

12-31-12	NA
09-30-12	0.81
06-30-12	0.80

Debt to Capital

12-31-12	NA
09-30-12	44.87
06-30-12	44.59

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At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1986 it has nearly tripled the S&P 500 with an average gain of +26% per year. These returns cover a period from 1986-2011 and were examined and attested by Baker Tilly, an independent accounting firm.

Visit performance for information about the performance numbers displayed above.

NYSE and AMEX data is at least 20 minutes delayed. NASDAQ data is at least 15 minutes delayed.

Southwest Gas Corp: (NYSE: SWX)

ZACKS RANK: 4-SELL

$43.73 0.05 (0.11%) **VOLUME 24,096** **JAN 22 12:06 PM ET**

Full Company Report Get Full Company Report for: Enter Symbol GO

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.

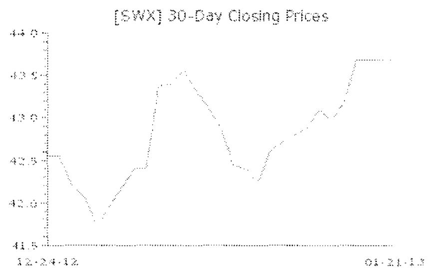
GENERAL INFORMATION

SOUTHWEST GAS
5241 SPRING MOUNTAIN . PO BOX 98510RD
LAS VEGAS, NV 89193-8510
Phone: 7028767237
Fax: 702-876-7037
Web: http://www.swgas.com
Email: NA

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/2012
Next EPS Date	03/05/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	43.68
52 Week High	46.08
52 Week Low	39.01
Beta	0.69
20 Day Moving Average	118,390.55
Target Price Consensus	46.00



% Price Change

4 Week	2.66
12 Week	-0.34
YTD	2.99

% Price Change Relative to S&P 500

4 Week	-1.44
12 Week	-5.31
YTD	-1.15

Share Information

Shares Outstanding (millions)	46.14
Market Capitalization (millions)	2,015.44
Short Ratio	6.27
Last Split Date	NA

Dividend Information

Dividend Yield	2.70%
Annual Dividend	$1.18
Payout Ratio	0.40
Change in Payout Ratio	NA
Last Dividend Payout / Amount	11/13/2012 / $0.29

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.23

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.38

Current Year EPS Consensus Estimate	2.75	30 Days Ago	2.38
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	2.38
Next EPS Report Date	03/05/2013	90 Days Ago	2.38

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	15.41
Trailing 12 Months	14.81
PEG Ratio	3.10

EPS Growth

vs. Previous Year	80.00%
vs. Previous Quarter	-140.00%

Sales Growth

vs. Previous Year	5.45%
vs. Previous Quarter	-9.27%

Price Ratios

Price/Book	1.59
Price/Cash Flow	7.08
Price / Sales	1.03

ROE

12-31-12	NA
09-30-12	10.82
06-30-12	10.43

ROA

12-31-12	NA
09-30-12	3.18
06-30-12	3.08

Current Ratio

12-31-12	NA
09-30-12	0.75
06-30-12	0.76

Quick Ratio

12-31-12	NA
09-30-12	0.75
06-30-12	0.76

Operating Margin

12-31-12	NA
09-30-12	7.00
06-30-12	6.71

Net Margin

12-31-12	NA
09-30-12	6.45
06-30-12	5.93

Pre-Tax Margin

12-31-12	NA
09-30-12	9.99
06-30-12	9.28

Book Value

12-31-12	NA
09-30-12	27.42
06-30-12	27.77

Inventory Turnover

12-31-12	NA
09-30-12	NA
06-30-12	NA

Debt-to-Equity

12-31-12	NA
09-30-12	0.99
06-30-12	0.94

Debt to Capital

12-31-12	NA
09-30-12	49.82
06-30-12	48.44

Wgl Holdings Inc: (NYSE: WGL)

ZACKS RANK: 3-HOLD

$40.96 0.42 (1.04%) **VOLUME 131,439** JAN 22 12:08 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

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.

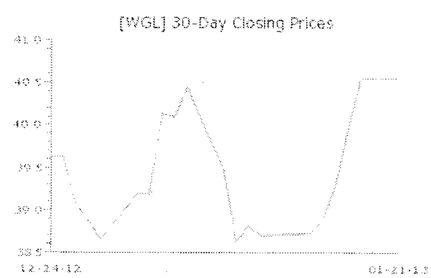
GENERAL INFORMATION

WGL HLDGS INC
101 CONSTITUTION AVE N.W.
WASHINGTON, DC 20080
Phone: 2026246011
Fax: 703-750-4828
Web: http://www.wglholdings.com
Email: douglas.bonawitz@washgas.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	September
Last Reported Quarter	12/31/2012
Next EPS Date	02/01/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	40.54
52 Week High	43.80
52 Week Low	35.96
Beta	0.21
20 Day Moving Average	292,326.00
Target Price Consensus	40.83



% Price Change

4 Week	2.32
12 Week	2.63
YTD	3.44

% Price Change Relative to S&P 500

4 Week	-1.76
12 Week	-2.48
YTD	-0.72

Share Information

Shares Outstanding (millions)	51.61
Market Capitalization (millions)	2,092.39
Short Ratio	9.21
Last Split Date	05/02/95

Dividend Information

Dividend Yield	3.95%
Annual Dividend	$1.60
Payout Ratio	0.59
Change in Payout Ratio	NA
Last Dividend Payout / Amount	01/08/2013 / $0.40

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.04
Current Year EPS Consensus Estimate	2.43
Estimated Long-Term EPS Growth Rate	5.30
Next EPS Report Date	02/01/2013

CONSENSUS RECOMMENDATIONS

Sub

Current (1=Strong Buy, 5=Strong Sell)	2.43
30 Days Ago	2.43
60 Days Ago	2.43
90 Days Ago	2.57

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	16.65
Trailing 12 Months	15.07
PEG Ratio	3.17

EPS Growth

vs. Previous Year	61.54%
vs. Previous Quarter	-225.00%

Sales Growth

vs. Previous Year	-6.32%
vs. Previous Quarter	-4.23%

Price Ratios

Price/Book	1.65
Price/Cash Flow	8.84
Price / Sales	0.86

ROE

12-31-12	NA
09-30-12	11.02
06-30-12	10.49

ROA

12-31-12	NA
09-30-12	3.49
06-30-12	3.34

Current Ratio

12-31-12	NA
09-30-12	1.10
06-30-12	1.35

Quick Ratio

12-31-12	NA
09-30-12	0.69
06-30-12	0.89

Operating Margin

12-31-12	NA
09-30-12	5.73
06-30-12	5.32

Net Margin

12-31-12	NA
09-30-12	5.82
06-30-12	4.19

Pre-Tax Margin

12-31-12	NA
09-30-12	9.67
06-30-12	7.63

Book Value

12-31-12	NA
09-30-12	24.62
06-30-12	24.87

Inventory Turnover

12-31-12	NA
09-30-12	7.09
06-30-12	7.29

Debt-to-Equity

12-31-12	NA
09-30-12	0.46
06-30-12	0.46

Debt to Capital

12-31-12	NA
09-30-12	31.23
06-30-12	30.98

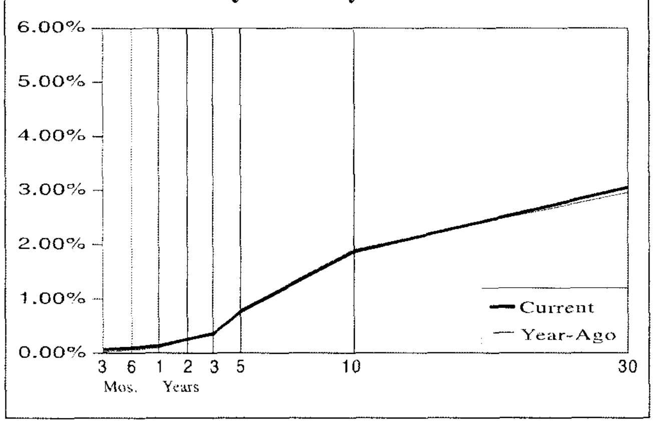
ATTACHMENT D

Selected Yields

	Recent (1/16/13)	3 Months Ago (10/17/12)	Year Ago (1/18/12)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.23	0.25	0.32
3-month LIBOR	0.30	0.32	0.56
Bank CDs			
6-month	0.10	0.12	0.22
1-year	0.13	0.16	0.34
5-year	0.70	0.86	1.16
U.S. Treasury Securities			
3-month	0.07	0.10	0.02
6-month	0.10	0.16	0.06
1-year	0.14	0.19	0.10
5-year	0.76	0.77	0.80
10-year	1.85	1.81	1.90
10-year (inflation-protected)	-0.73	-0.67	-0.21
30-year	3.05	2.98	2.96
30-year Zero	3.25	3.23	3.14

	Recent (1/16/13)	3 Months Ago (10/17/12)	Year Ago (1/18/12)
Mortgage-Backed Securities			
GNMA 5.5%	1.77	1.05	1.07
FHLMC 5.5% (Gold)	1.98	1.89	1.94
FNMA 5.5%	1.75	1.54	1.72
FNMA ARM	2.23	2.22	2.35
Corporate Bonds			
Financial (10-year) A	3.05	3.10	4.00
Industrial (25/30-year) A	3.96	3.88	4.25
Utility (25/30-year) A	3.96	3.94	4.33
Utility (25/30-year) Baa/BBB	4.31	4.27	4.94
Foreign Bonds (10-Year)			
Canada	1.89	1.81	1.96
Germany	1.57	1.63	1.79
Japan	0.76	0.77	0.97
United Kingdom	2.00	1.92	1.96
Preferred Stocks			
Utility A	5.48	5.09	4.95
Financial BBB	5.91	6.05	6.18
Financial Adjustable A	5.49	5.49	5.49
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.60	3.64	3.62
25-Bond Index (Revs)	4.26	4.32	4.74
General Obligation Bonds (GOs)			
1-year Aaa	0.19	0.20	0.17
1-year A	0.75	0.84	1.02
5-year Aaa	0.80	0.68	0.85
5-year A	1.76	1.67	1.93
10-year Aaa	1.89	1.89	1.93
10-year A	2.84	3.01	2.91
25/30-year Aaa	3.11	3.28	3.56
25/30-year A	4.79	4.79	4.96
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.22	4.23	4.40
Electric AA	4.32	4.31	4.54
Housing AA	4.63	4.68	5.01
Hospital AA	4.43	4.41	4.61
Toll Road Aaa	4.35	4.23	4.48

Treasury Security Yield Curve



Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	1/9/13	12/26/12	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1463477	1452681	10796	1441882	1448267	1472764
Borrowed Reserves	590	740	-150	1041	2108	4510
Net Free/Borrowed Reserves	1462887	1451941	10946	1440842	1446159	1468254

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	12/31/12	12/24/12	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2453.2	2459.6	-6.4	14.0%	18.3%	13.0%
M2 (M1+savings+small time deposits)	10505.5	10430.6	74.9	12.8%	10.9%	8.2%

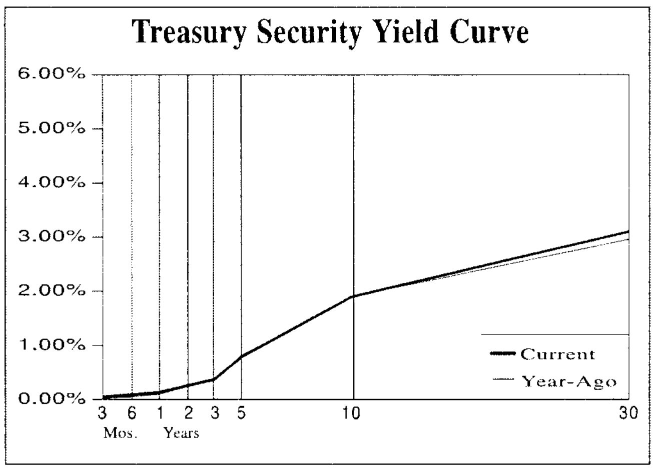
Source: United States Federal Reserve Bank

Selected Yields

	Recent (1/09/13)	3 Months Ago (10/10/12)	Year Ago (1/11/12)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.23	0.26	0.25
3-month LIBOR	0.31	0.34	0.58
Bank CDs			
6-month	0.10	0.13	0.22
1-year	0.13	0.16	0.34
5-year	0.70	0.86	1.17
U.S. Treasury Securities			
3-month	0.05	0.09	0.02
6-month	0.09	0.15	0.05
1-year	0.13	0.17	0.10
5-year	0.79	0.66	0.82
10-year	1.90	1.70	1.90
10-year (inflation-protected)	-0.71	-0.83	-0.16
30-year	3.10	2.90	2.96
30-year Zero	3.30	3.11	3.15

	Recent (1/09/13)	3 Months Ago (10/10/12)	Year Ago (1/11/12)
Mortgage-Backed Securities			
GNMA 5.5%	1.78	0.78	0.91
FHLMC 5.5% (Gold)	2.16	1.84	1.91
FNMA 5.5%	1.87	1.52	1.74
FNMA ARM	2.16	2.22	2.35
Corporate Bonds			
Financial (10-year) A	3.11	3.03	4.12
Industrial (25/30-year) A	3.99	3.80	4.22
Utility (25/30-year) A	4.00	3.84	4.17
Utility (25/30-year) Baa/BBB	4.36	4.15	4.90
Foreign Bonds (10-Year)			
Canada	1.91	1.79	1.94
Germany	1.48	1.49	1.81
Japan	0.83	0.77	0.97
United Kingdom	2.02	1.77	2.01
Preferred Stocks			
Utility A	5.50	5.09	4.94
Financial BBB	6.13	6.04	6.27
Financial Adjustable A	5.48	5.49	5.49
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.68	3.61	3.83
25-Bond Index (Revs)	4.30	4.28	4.93
General Obligation Bonds (GOs)			
1-year Aaa	0.21	0.20	0.17
1-year A	0.80	0.83	1.00
5-year Aaa	0.87	0.67	0.89
5-year A	1.83	1.66	1.98
10-year Aaa	1.96	1.87	1.99
10-year A	2.90	2.99	3.03
25/30-year Aaa	3.15	3.29	3.70
25/30-year A	4.85	4.79	5.12
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.25	4.23	4.49
Electric AA	4.35	4.31	4.63
Housing AA	4.66	4.68	5.10
Hospital AA	4.50	4.41	4.72
Toll Road Aaa	4.39	4.23	4.53

Source: Bloomberg Finance L.P.



Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 12/26/12	12/12/12	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1452680	1463862	-11182	1428705	1445624	1473060
Borrowed Reserves	740	947	-207	1194	2432	4834
Net Free/Borrowed Reserves	1451940	1462915	-10975	1427511	1443193	1468226

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 12/24/12	12/17/12	Change	Ann'l Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2459.6	2435.5	24.1	12.0%	19.4%	13.5%
M2 (M1+savings+small time deposits)	10431.5	10393.0	38.5	12.8%	10.3%	8.5%

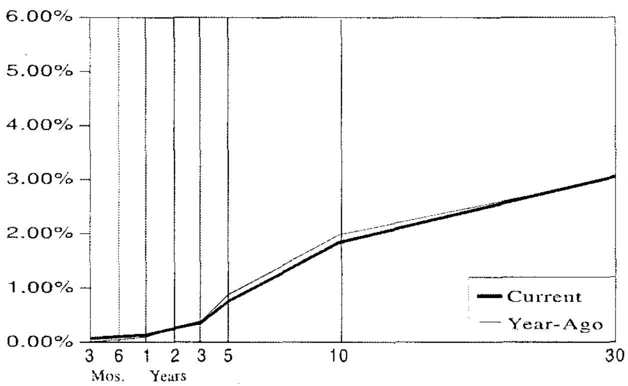
Source: United States Federal Reserve Bank

Selected Yields

	Recent (1/02/12)	3 Months Ago (10/03/12)	Year Ago (1/04/12)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.25	0.28	0.25
3-month LIBOR	0.31	0.35	0.58
Bank CDs			
6-month	0.10	0.13	0.22
1-year	0.13	0.16	0.34
5-year	0.70	0.86	1.16
U.S. Treasury Securities			
3-month	0.07	0.09	0.01
6-month	0.11	0.13	0.05
1-year	0.14	0.16	0.10
5-year	0.76	0.62	0.88
10-year	1.84	1.57	1.98
10-year (inflation-protected)	-0.69	-0.90	-0.14
30-year	3.05	2.68	3.03
30-year Zero	3.29	3.08	3.13
Mortgage-Backed Securities			
GNMA 5.5%	1.75	0.77	0.99
FHLMC 5.5% (Gold)	2.12	2.00	2.03
FNMA 5.5%	1.81	1.69	1.86
FNMA ARM	2.16	2.22	2.35
Corporate Bonds			
Financial (10-year) A	3.10	3.00	4.25
Industrial (25/30-year) A	3.99	3.78	4.33
Utility (25/30-year) A	4.03	3.84	4.22
Utility (25/30-year) Baa/BBB	4.35	4.16	4.95
Foreign Bonds (10-Year)			
Canada	1.87	1.74	1.99
Germany	1.44	1.47	1.92
Japan	0.79	0.77	0.99
United Kingdom	1.99	1.72	2.05
Preferred Stocks			
Utility A	5.64	5.14	5.11
Financial BBB	6.01	5.98	6.38
Financial Adjustable A	5.48	5.48	5.48
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.58	3.67	3.88
25-Bond Index (Revs)	4.28	4.31	4.97
General Obligation Bonds (GOs)			
1-year Aaa	0.21	0.19	0.22
1-year A	0.83	0.82	1.07
5-year Aaa	0.90	0.69	0.92
5-year A	1.83	1.62	2.06
10-year Aaa	1.97	1.90	2.07
10-year A	2.87	3.01	3.12
25/30-year Aaa	3.16	3.30	3.80
25/30-year A	4.85	4.73	5.20
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.23	4.22	4.53
Electric AA	4.33	4.30	4.70
Housing AA	4.64	4.67	5.26
Hospital AA	4.50	4.42	4.72
Toll Road Aaa	4.42	4.23	4.53

Source: Bloomberg Finance L.P.

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 12/26/12	12/12/12	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1452681	1463862	-11181	1428705	1445624	1473060
Borrowed Reserves	740	947	-207	1194	2432	4834
Net Free/Borrowed Reserves	1451941	1462915	-10974	1427511	1443193	1468226

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 12/17/12	12/10/12	Change	Ann'l Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2435.5	2429.1	6.4	9.0%	17.2%	12.3%
M2 (M1+savings+small time deposits)	10391.3	10355.0	36.3	11.1%	9.7%	8.2%

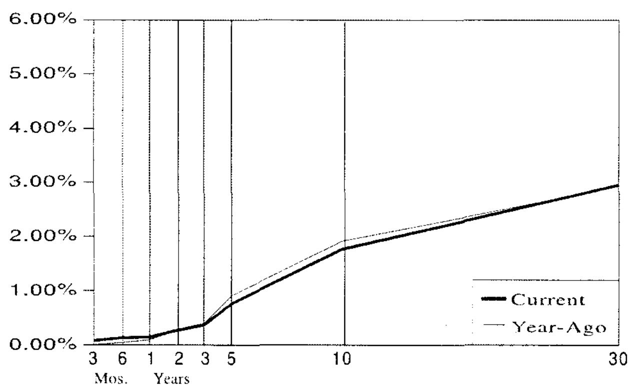
Source: United States Federal Reserve Bank

Selected Yields

TAXABLE	Recent (12/26/12)	3 Months Ago (9/26/12)	Year Ago (12/28/11)
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.24	0.26	0.19
3-month LIBOR	0.31	0.36	0.58
Bank CDs			
6-month	0.10	0.13	0.22
1-year	0.13	0.17	0.34
5-year	0.70	0.86	1.15
U.S. Treasury Securities			
3-month	0.08	0.09	0.01
6-month	0.13	0.13	0.05
1-year	0.15	0.17	0.10
5-year	0.77	0.64	0.91
10-year	1.77	1.63	1.92
10-year (inflation-protected)	-0.78	-0.81	-0.11
30-year	2.95	2.81	2.92
30-year Zero	3.16	2.99	3.02

	Recent (12/26/12)	3 Months Ago (9/26/12)	Year Ago (12/28/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.79	0.65	1.12
FHLMC 5.5% (Gold)	2.16	1.93	2.12
FNMA 5.5%	1.82	1.64	1.99
FNMA ARM	2.17	2.25	2.37
Corporate Bonds			
Financial (10-year) A	3.06	2.98	4.17
Industrial (25/30-year) A	3.86	3.68	4.26
Utility (25/30-year) A	3.92	3.82	4.14
Utility (25/30-year) Baa/BBB	4.24	4.16	4.78
Foreign Bonds (10-Year)			
Canada	1.82	1.75	1.96
Germany	1.37	1.46	1.89
Japan	0.79	0.78	1.00
United Kingdom	1.89	1.69	2.01
Preferred Stocks			
Utility A	5.54	5.08	5.37
Financial BBB	6.20	5.93	6.71
Financial Adjustable A	5.47	5.47	5.48

Treasury Security Yield Curve



TAX-EXEMPT	Recent (12/26/12)	3 Months Ago (9/26/12)	Year Ago (12/28/11)
Bond Buyer Indexes			
20-Bond Index (GOs)	3.64	3.72	3.92
25-Bond Index (Revs)	4.26	4.37	5.01
General Obligation Bonds (GOs)			
1-year Aaa	0.21	0.20	0.22
1-year A	0.81	0.78	1.06
5-year Aaa	0.90	0.76	0.97
5-year A	1.81	1.74	2.07
10-year Aaa	1.99	1.98	2.12
10-year A	2.85	3.10	3.23
25/30-year Aaa	3.16	3.34	3.86
25/30-year A	4.83	4.81	5.24
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.23	4.25	4.56
Electric AA	4.37	4.36	4.73
Housing AA	4.64	4.70	5.29
Hospital AA	4.49	4.45	4.87
Toll Road Aaa	4.41	4.30	4.54

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	12/12/12	11/28/12	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1463863	1427749	36114	1424705	1448342	1475871
Borrowed Reserves	947	990	-43	1375	2768	5171
Net Free/Borrowed Reserves	1462916	1426759	36157	1423330	1445573	1470700

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

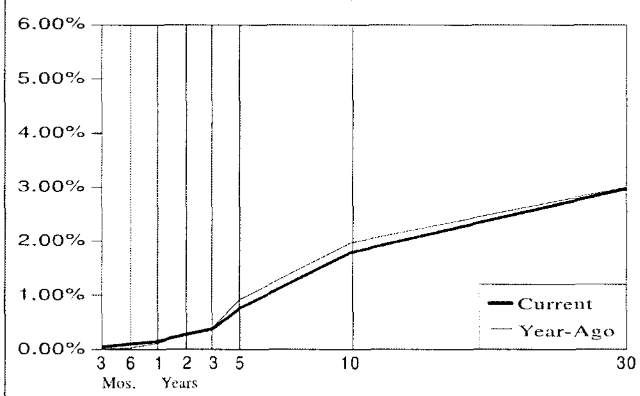
	Recent Levels			Ann'l Growth Rates Over the Last...		
	12/10/12	12/3/12	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2429.1	2406.2	22.9	10.1%	16.5%	11.9%
M2 (M1+savings+small time deposits)	10355.5	10300.7	54.8	10.2%	8.6%	7.9%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (12/19/12)	3 Months Ago (9/19/12)	Year Ago (12/21/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.22	0.27	0.29
3-month LIBOR	0.31	0.38	0.57
Bank CDs			
6-month	0.10	0.13	0.22
1-year	0.13	0.17	0.34
5-year	0.70	0.86	1.15
U.S. Treasury Securities			
3-month	0.05	0.10	0.01
6-month	0.10	0.13	0.03
1-year	0.15	0.18	0.11
5-year	0.76	0.67	0.92
10-year	1.79	1.74	1.97
10-year (inflation-protected)	-0.73	-0.77	-0.12
30-year	2.97	2.93	3.00
30-year Zero	3.23	3.19	3.10

Treasury Security Yield Curve



	Recent (12/19/12)	3 Months Ago (9/19/12)	Year Ago (12/21/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.77	0.76	1.05
FHLMC 5.5% (Gold)	2.13	1.92	2.12
FNMA 5.5%	1.84	1.62	1.95
FNMA ARM	2.17	2.25	2.37
Corporate Bonds			
Financial (10-year) A	3.08	3.16	4.11
Industrial (25/30-year) A	3.93	3.84	4.21
Utility (25/30-year) A	3.99	3.95	4.12
Utility (25/30-year) Baa/BBB	4.33	4.33	4.77
Foreign Bonds (10-Year)			
Canada	1.85	1.89	1.96
Germany	1.43	1.62	1.93
Japan	0.77	0.82	0.98
United Kingdom	1.96	1.84	2.07
Preferred Stocks			
Utility A	5.57	5.22	5.36
Financial BBB	5.96	5.94	6.55
Financial Adjustable A	5.47	5.47	5.47
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.44	3.79	3.92
25-Bond Index (Revs)	4.12	4.42	5.01
General Obligation Bonds (GOs)			
1-year Aaa	0.21	0.20	0.21
1-year A	0.81	0.82	1.03
5-year Aaa	0.87	0.83	0.97
5-year A	1.76	1.85	2.07
10-year Aaa	1.95	2.08	2.15
10-year A	2.80	3.24	3.25
25/30-year Aaa	3.16	3.39	3.86
25/30-year A	4.81	4.85	5.24
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.21	4.30	4.56
Electric AA	4.35	4.46	4.74
Housing AA	4.62	4.79	5.34
Hospital AA	4.42	4.50	4.87
Toll Road Aaa	4.41	4.32	4.54

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	12/12/12	11/28/12	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1463911	1427749	36162	1424712	1448345	1475872
Borrowed Reserves	947	990	-43	1375	2768	5171
Net Free/Borrowed Reserves	1462964	1426759	36205	1423337	1445577	1470701

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	12/3/12	11/26/12	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2406.1	2391.2	14.9	9.2%	14.4%	11.1%
M2 (M1+savings+small time deposits)	10300.3	10264.1	36.2	9.3%	8.7%	7.6%

Source: United States Federal Reserve Bank

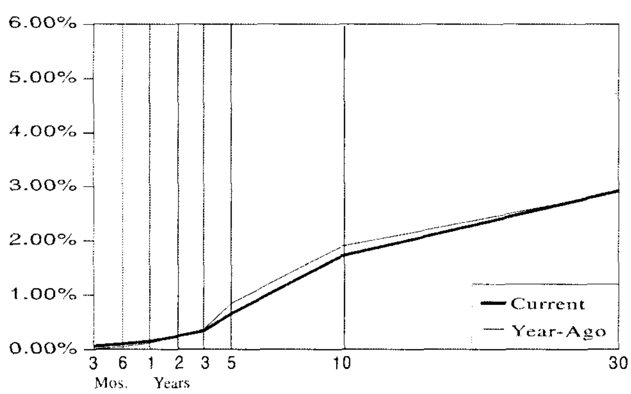
Selected Yields

	Recent (12/12/12)	3 Months Ago (9/12/12)	Year Ago (12/14/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.26	0.27	0.28
3-month LIBOR	0.31	0.39	0.56
Bank CDs			
6-month	0.10	0.13	0.22
1-year	0.16	0.18	0.35
5-year	0.74	0.94	1.17
U.S. Treasury Securities			
3-month	0.06	0.09	0.01
6-month	0.10	0.12	0.05
1-year	0.15	0.16	0.11
5-year	0.66	0.65	0.85
10-year	1.72	1.73	1.90
10-year (inflation-protected)	-0.84	-0.63	-0.08
30-year	2.92	2.90	2.90
30-year Zero	3.13	3.14	3.00

	Recent (12/12/12)	3 Months Ago (9/12/12)	Year Ago (12/14/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.75	0.81	1.03
FHLMC 5.5% (Gold)	2.05	1.94	2.16
FNMA 5.5%	1.75	1.70	2.05
FNMA ARM	2.17	2.25	2.37
Corporate Bonds			
Financial (10-year) A	2.99	3.19	4.23
Industrial (25/30-year) A	3.84	3.83	4.37
Utility (25/30-year) A	3.90	3.97	4.23
Utility (25/30-year) Baa/BBB	4.21	4.33	4.87
Foreign Bonds (10-Year)			
Canada	1.76	1.90	1.96
Germany	1.34	1.62	1.92
Japan	0.70	0.81	1.00
United Kingdom	1.82	1.83	2.09
Preferred Stocks			
Utility A	5.04	5.22	5.23
Financial BBB	5.96	6.10	6.87
Financial Adjustable A	5.46	5.46	5.46
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.27	3.73	3.93
25-Bond Index (Revs)	4.06	4.43	5.03
General Obligation Bonds (GOs)			
1-year Aaa	0.21	0.18	0.20
1-year A	0.79	0.84	1.11
5-year Aaa	0.73	0.78	1.00
5-year A	1.66	1.81	2.04
10-year Aaa	1.78	1.99	2.20
10-year A	2.70	3.14	3.34
25/30-year Aaa	3.06	3.34	3.89
25/30-year A	4.69	4.79	5.26
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.18	4.25	4.58
Electric AA	4.32	4.41	4.80
Housing AA	4.59	4.74	5.43
Hospital AA	4.31	4.46	4.88
Toll Road Aaa	4.27	4.28	4.54

Source: Bloomberg Finance L.P.

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 11/28/12	11/14/12	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1427749	1438778	-11029	1422842	1448196	1475758
Borrowed Reserves	990	1128	-138	1599	3123	5507
Net Free/Borrowed Reserves	1426759	1437650	-10891	1421243	1445073	1470251

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

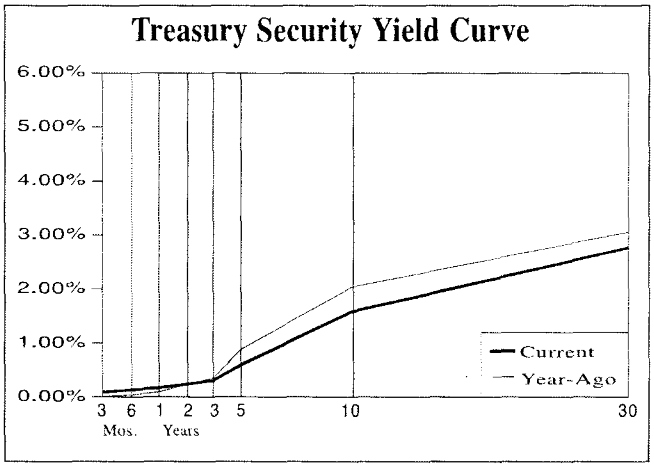
	Recent Levels 11/26/12	11/19/12	Change	Ann'l Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2391.2	2407.2	-16.0	12.9%	13.6%	11.1%
M2 (M1+savings+small time deposits)	10263.9	10250.1	13.8	8.5%	7.7%	7.2%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (12/05/12)	3 Months Ago (9/05/12)	Year Ago (12/07/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.22	0.29	0.52
3-month LIBOR	0.31	0.41	0.54
Bank CDs			
6-month	0.11	0.13	0.22
1-year	0.16	0.18	0.35
5-year	0.76	0.94	1.17
U.S. Treasury Securities			
3-month	0.09	0.10	0.01
6-month	0.13	0.13	0.04
1-year	0.17	0.17	0.09
5-year	0.60	0.65	0.89
10-year	1.58	1.65	2.03
10-year (inflation-protected)	-0.90	-0.70	-0.05
30-year	2.77	2.76	3.06
30-year Zero	3.00	2.91	3.16

	Recent (12/05/12)	3 Months Ago (9/05/12)	Year Ago (12/07/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.65	0.75	1.21
FHLMC 5.5% (Gold)	2.03	1.89	2.30
FNMA 5.5%	1.73	1.66	2.01
FNMA ARM	2.17	2.25	2.37
Corporate Bonds			
Financial (10-year) A	2.91	3.05	4.32
Industrial (25/30-year) A	3.74	3.69	4.39
Utility (25/30-year) A	3.80	3.77	4.25
Utility (25/30-year) Baa/BBB	4.10	4.15	4.92
Foreign Bonds (10-Year)			
Canada	1.69	1.76	2.06
Germany	1.35	1.48	2.10
Japan	0.70	0.78	1.05
United Kingdom	1.78	1.64	2.24
Preferred Stocks			
Utility A	4.98	5.24	5.07
Financial BBB	5.96	6.09	6.78
Financial Adjustable A	5.53	5.53	5.53



	Recent (12/05/12)	3 Months Ago (9/05/12)	Year Ago (12/07/11)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.29	3.72	4.12
25-Bond Index (Revs)	4.08	4.45	5.09
General Obligation Bonds (GOs)			
1-year Aaa	0.20	0.18	0.21
1-year A	0.76	0.86	1.10
5-year Aaa	0.69	0.77	1.12
5-year A	1.63	1.82	2.20
10-year Aaa	1.73	1.94	2.37
10-year A	2.75	3.08	3.37
25/30-year Aaa	3.08	3.34	3.93
25/30-year A	4.66	4.79	5.28
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.13	4.21	4.61
Electric AA	4.24	4.44	4.83
Housing AA	4.54	4.74	5.53
Hospital AA	4.30	4.46	4.90
Toll Road Aaa	4.22	4.27	4.56

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 11/28/12	11/14/12	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1427758	1438778	-11020	1422843	1448196	1475758
Borrowed Reserves	990	1128	-138	1599	3123	5507
Net Free/Borrowed Reserves	1426768	1437650	-10882	1421244	1445074	1470251

MONEY SUPPLY

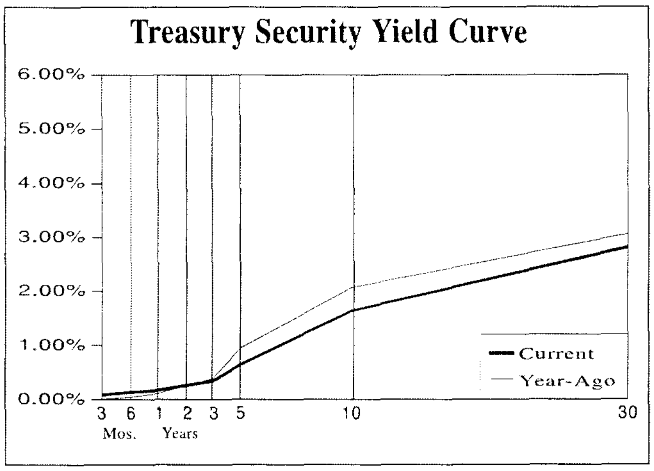
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 11/19/12	11/12/12	Change	Ann'l Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2407.1	2409.9	-2.8	17.1%	14.7%	12.1%
M2 (M1+savings+small time deposits)	10250.2	10269.5	-19.3	9.2%	7.3%	7.1%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (11/28/12)	3 Months Ago (8/29/12)	Year Ago (11/30/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.23	0.30	0.60
3-month LIBOR	0.31	0.42	0.53
Bank CDs			
6-month	0.11	0.13	0.17
1-year	0.16	0.18	0.21
5-year	0.76	0.94	1.14
U.S. Treasury Securities			
3-month	0.09	0.10	0.01
6-month	0.14	0.14	0.05
1-year	0.17	0.18	0.11
5-year	0.65	0.68	0.95
10-year	1.64	1.68	2.07
10-year (inflation-protected)	-0.80	-0.66	-0.01
30-year	2.81	2.74	3.06
30-year Zero	3.03	2.97	3.20



	Recent (11/28/12)	3 Months Ago (8/29/12)	Year Ago (11/30/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.70	1.00	1.35
FHLMC 5.5% (Gold)	2.08	1.99	2.31
FNMA 5.5%	1.71	1.80	2.09
FNMA ARM	2.19	2.27	2.37
Corporate Bonds			
Financial (10-year) A	2.98	3.03	4.58
Industrial (25/30-year) A	3.75	3.76	4.42
Utility (25/30-year) A	3.77	3.82	4.26
Utility (25/30-year) Baa/BBB	4.13	4.26	4.94
Foreign Bonds (10-Year)			
Canada	1.72	1.80	2.15
Germany	1.37	1.38	2.28
Japan	0.72	0.80	1.07
United Kingdom	1.77	1.50	2.31
Preferred Stocks			
Utility A	5.17	5.37	5.05
Financial BBB	6.11	6.08	6.32
Financial Adjustable A	5.53	5.53	5.53
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.37	3.76	4.07
25-Bond Index (Revs)	4.14	4.49	5.06
General Obligation Bonds (GOs)			
1-year Aaa	0.18	0.18	0.24
1-year A	0.77	0.88	1.10
5-year Aaa	0.69	0.77	1.20
5-year A	1.64	1.82	2.30
10-year Aaa	1.75	2.02	2.45
10-year A	2.78	3.09	3.50
25/30-year Aaa	3.12	3.35	3.99
25/30-year A	4.68	4.79	5.36
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.14	4.22	4.62
Electric AA	4.25	4.45	4.84
Housing AA	4.55	4.75	5.54
Hospital AA	4.30	4.46	4.92
Toll Road Aaa	4.22	4.27	4.57

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	11/14/12	10/31/12	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1438778	1422939	15839	1430430	1449838	1479637
Borrowed Reserves	1128	1363	-235	1961	3513	5862
Net Free/Borrowed Reserves	1437650	1421576	16074	1428469	1446325	1473775

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	11/12/12	11/5/12	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2409.9	2421.1	-11.2	17.3%	14.6%	12.8%
M2 (M1+savings+small time deposits)	10269.5	10293.2	-23.7	8.9%	7.9%	7.2%

Source: United States Federal Reserve Bank

ARIZONA WATER COMPANY
DOCKET NO. W-01445A-12-0348
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TEST YEAR ENDED DECEMBER 31, 2011
COST OF CAPITAL SUMMARY

WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	LONG-TERM DEBT	75,000,000	-	75,000,000	48.95%	6.82%	3.34%
3	COMMON EQUITY	78,221,194	-	78,221,194	51.05%	8.75%	4.47%
4	TOTAL CAPITALIZATION	$ 153,221,194	$ -	$ 153,221,194	100.00%		
5	**WEIGHTED AVERAGE COST OF CAPITAL**						**7.81%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1, PAGE 1
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): LINES 1 THRU 3 / LINE 4
COLUMN (E): LINES 1 AND 2, SCHEDULE WAR 1, PAGE 2 OF 3, LINE 5; TESTIMONY, WAR
COLUMN (F): LINES 1 THRU 3; COLUMN (D) X COLUMN (E)
COLUMN (F): LINE 5, SUM OF COLUMN (G) LINES 1 THRU 3

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TEST YEAR ENDED DECEMBER 31, 201
COST OF CAPITAL SUMMARY

#REF!
SCHEDULE WAR - 1

WEIGHTED AVERAGE COST OF LONG-TERM DEBT

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ANNUAL COST	(E) CAPITAL RATIO	(F) INTEREST RATE	(G) WEIGHTED COST
1	SERIES K, DUE APRIL 1, 2031	$ 15,000,000	$ -	$ 15,000,000	$ 1,206,855	20.00%	8.05%	1.61%
2	SERIES L, DUE AUGUST 1, 2036	25,000,000	-	25,000,000	1,575,650	33.33%	6.30%	2.10%
3	SERIES M, DUE AUGUST 1, 2038	35,000,000	-	35,000,000	2,336,110	46.67%	6.67%	3.11%
4	TOTAL CAPITALIZATION/INTEREST	$ 75,000,000		$ 75,000,000	$ 5,118,615			
5	**WEIGHTED AVERAGE COST OF LONG-TERM DEBT**							**6.82%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1, PAGE 2
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COMPANY SCHEDULE D-1, PAGE 2
COLUMN (E): COLUMN (D), LINES 1 THRU 3 / COLUMN (D) LINE 4
COLUMN (F): LINES 1 THRU 3; COLUMN (D) / COLUMN (C)
COLUMN (G): LINES 1 THRU 3; COLUMN (E) X COLUMN (F)
COLUMN (G): LINE 5, SUM OF COLUMN (G) LINES 1 THRU 3

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - WATER COMPANY SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	7.97%	SCHEDULE WAR-2, COLUMN (C), LINE 5
3	DCF - NATURAL GAS LDC SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	8.75%	SCHEDULE WAR-2, COLUMN (C), LINE 13
4	**AVERAGE OF DCF ESTIMATES**	**8.36%**	(LINE 2 + LINE 3) ÷ 2
5	**CAPM METHODOLOGY**		
6	CAPM - WATER COMPANY GEOMETRIC MEAN ESTIMATE	5.79%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 5
7	CAPM - NATURAL GAS LDC GEOMETRIC MEAN ESTIMATE	5.64%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 13
8	CAPM - WATER COMPANY ARITHMETIC MEAN ESTIMATE	6.90%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 5
9	CAPM - NATURAL GAS LDC ARITHMETIC MEAN ESTIMATE	6.69%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 13
10	**AVERAGE OF CAPM ESTIMATES**	**6.25%**	(SUM OF LINES 6 THRU 9) ÷ 4
11	**AVERAGE OF DCF AND CAPM ESTIMATES**	**7.31%**	(SUM OF LINES 4 AND 10) ÷ 2
12	**FINAL COST OF COMMON EQUITY ESTIMATE**	**8.75%**	TESTIMONY WAR

ARIZONA WATER COMPANY
DOCKET NO. W-01445A-12-0348
DCF COST OF EQUITY CAPITAL

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	AWK	AMERICAN WATER WORKS COMPANY, INC.	2.66%	+	4.85%	=	7.50%
2	AWR	AMERICAN STATES WATER CO.	2.94%	+	5.66%		8.60%
3	CWT	CALIFORNIA WATER SERVICE GROUP	3.40%	+	5.32%	=	8.72%
4	MSEX	MIDDLESEX WATER COMPANY	3.91%	+	3.59%	=	7.51%
5	SJW	SJW CORPORATION	2.76%	+	4.23%	=	6.99%
6	WTR	AQUA AMERICA, INC.	2.72%	+	5.77%	=	8.49%
7	**WATER COMPANY AVERAGE**						**7.97%**
8	GAS	AGL RESOURCES, INC.	4.57%	+	2.00%	=	6.57%
9	ATO	ATMOS ENERGY CORP.	3.90%	+	3.98%	=	7.88%
10	LG	LACLEDE GROUP, INC.	4.26%	+	4.13%	=	8.39%
11	NJR	NEW JERSEY RESOURCES CORPORATION	3.97%	+	7.01%	=	10.97%
12	NWN	NORTHWEST NATURAL GAS CO.	4.11%	+	4.29%	=	8.40%
13	PNY	PIEDMONT NATURAL GAS COMPANY	3.79%	+	3.01%	=	6.80%
14	SJI	SOUTH JERSEY INDUSTRIES, INC.	3.15%	+	9.65%	=	12.79%
15	SWX	SOUTHWEST GAS CORPORATION	2.76%	+	6.40%	=	9.16%
16	WGL	WGL HOLDINGS, INC.	4.08%	+	3.68%	=	7.75%
17	**NATURAL GAS LDC AVERAGE**						**8.75%**

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, 2011
DIVIDEND YIELD CALCULATION

DOCKET NO. W-01445A-12-0348
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	/	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	AWK	AMERICAN WATER WORKS COMPANY, INC.	$1.00	/	$37.62	=	2.66%
2	AWR	AMERICAN STATES WATER CO.	1.42	/	48.26	=	2.94%
3	CWT	CALIFORNIA WATER SERVICE GROUP	0.63	/	18.52	=	3.40%
4	MSEX	MIDDLESEX WATER COMPANY	0.75	/	19.17	=	3.91%
5	SJW	SJW CORPORATION	0.71	/	25.69		2.76%
6	WTR	AQUA AMERICA, INC.	0.70	/	25.73	=	2.72%
7	**WATER COMPANY AVERAGE**						**3.07%**
8	GAS	AGL RESOURCES, INC.	$1.84	/	$40.29	=	4.57%
9	ATO	ATMOS ENERGY CORP.	1.40	/	35.85	=	3.90%
10	LG	LACLEDE GROUP, INC.	1.66	/	38.96	=	4.26%
11	NJR	NEW JERSEY RESOURCES CORPORATION	1.60	/	40.32	=	3.97%
12	NWN	NORTHWEST NATURAL GAS CO.	1.82	/	44.32	=	4.11%
13	PNY	PIEDMONT NATURAL GAS COMPANY	1.20	/	31.66	=	3.79%
14	SJI	SOUTH JERSEY INDUSTRIES, INC.	1.61	/	51.23	=	3.15%
15	SWX	SOUTHWEST GAS CORPORATION	1.18	/	42.71	=	2.76%
16	WGL	WGL HOLDINGS, INC.	1.60	/	39.22	=	4.08%
17	**NATURAL GAS LDC AVERAGE**						**3.84%**

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 01/18/2013 (WATER COMPANIES) AND 12/07/2012 (NATURAL GAS LDC's).
COLUMN (B): EIGHT WEEK AVERAGE OF ADJUSTED CLOSING PRICES FROM 12/03/2012 TO 01/25/2013 STOCK QUOTES OBTAINED THROUGH YAHOO! FINANCE WEB SITE - HISTORICAL QUOTES (http://finance.yahoo.com).
COLUMN (C): COLUMN (A) DIVIDED BY COLUMN (B)

NOTE:
CLOSING STOCK PRICES ARE ADJUSTED FOR DIVIDENDS AND STOCK SPLITS.

ARIZONA WATER COMPANY
TEST YEAR ENDED DECEMBER 31, 2011
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	AWK	AMERICAN WATER WORKS COMPANY, INC.	4.50%	+	0.35%	=	4.85%
2	AWR	AMERICAN STATES WATER CO.	5.10%	+	0.56%	=	5.66%
3	CWT	CALIFORNIA WATER SERVICE GROUP	4.50%	+	0.82%	=	5.32%
4	MSEX	MIDDLESEX WATER COMPANY	3.00%	+	0.59%	=	3.59%
5	SJW	SJW CORPORATION	3.00%	+	1.23%	=	4.23%
6	WTR	AQUA AMERICA, INC.	5.10%	+	0.67%	=	5.77%
7	**WATER COMPANY AVERAGE**						**4.90%**
8	GAS	AGL RESOURCES, INC.	2.00%	+	0.00%	=	2.00%
9	ATO	ATMOS ENERGY CORP.	3.50%	+	0.48%	=	3.98%
10	LG	LACLEDE GROUP, INC.	3.90%	+	0.23%	=	4.13%
11	NJR	NEW JERSEY RESOURCES CORPORATION	7.00%	+	0.01%	=	7.01%
12	NWN	NORTHWEST NATURAL GAS CO.	4.00%	+	0.29%	=	4.29%
13	PNY	PIEDMONT NATURAL GAS COMPANY	3.00%	+	0.01%	=	3.01%
14	SJI	SOUTH JERSEY INDUSTRIES, INC.	7.50%	+	2.15%	=	9.65%
15	SWX	SOUTHWEST GAS CORPORATION	6.00%	+	0.40%	=	6.40%
16	WGL	WGL HOLDINGS, INC.	3.50%	+	0.18%	=	3.68%
17	**NATURAL GAS LDC AVERAGE**						**4.90%**

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, 2011
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. W-01445A-12-0348
SCHEDULE WAR - 4

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) / 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	AWK	AMERICAN WATER WORKS COMPANY, INC	1.40%	x	{ [((1.49) + 1) / 2] - 1 }	=	0.35%
2	AWR	AMERICAN STATES WATER CO.	1.00%	x	{ [((2.12) + 1) / 2] - 1 }	=	0.56%
3	CWT	CALIFORNIA WATER SERVICE GROUP	2.60%	x	{ [((1.63) + 1) / 2] - 1 }	=	0.82%
4	MSEX	MIDDLESEX WATER COMPANY	1.90%	x	{ [((1.62) + 1) / 2] - 1 }	=	0.59%
5	SJW	SJW CORPORATION	3.70%	x	{ [((1.66) + 1) / 2] - 1 }	=	1.23%
6	WTR	AQUA AMERICA, INC.	0.75%	x	{ [((2.78) + 1) / 2] - 1 }	=	0.67%
7	**WATER COMPANY AVERAGE**						**0.70%**
8	GAS	AGL RESOURCES, INC.	0.01%	x	{ [((1.30) + 1) / 2] - 1 }	=	0.00%
9	ATO	ATMOS ENERGY CORP.	2.60%	x	{ [((1.37) + 1) / 2] - 1 }	=	0.48%
10	LG	LACLEDE GROUP, INC.	1.00%	x	{ [((1.46) + 1) / 2] - 1 }	=	0.23%
11	NJR	NEW JERSEY RESOURCES CORPORATION	0.01%	x	{ [((2.22) + 1) / 2] - 1 }	=	0.01%
12	NWN	NORTHWEST NATURAL GAS CO.	0.90%	x	{ [((1.64) + 1) / 2] - 1 }	=	0.29%
13	PNY	PIEDMONT NATURAL GAS COMPANY	0.01%	x	{ [((2.29) + 1) / 2] - 1 }	=	0.01%
14	SJI	SOUTH JERSEY INDUSTRIES, INC.	3.50%	x	{ [((2.23) + 1) / 2] - 1 }	=	2.15%
15	SWX	SOUTHWEST GAS CORPORATION	1.50%	x	{ [((1.53) + 1) / 2] - 1 }	=	0.40%
16	WGL	WGL HOLDINGS, INC.	0.60%	x	{ [((1.58) + 1) / 2] - 1 }	=	0.18%
17	**NATURAL GAS LDC AVERAGE**						**0.41%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 01/18/2013 (WATER COMPANIES) AND 12/07/2012 (NATURAL GAS LDC's)
COLUMN (C): COLUMN (A) x COLUMN (B)

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	AWK	AMERICAN WATER WORKS COMPANY, INC.	2007	-		NMF		-	28.39	160.00	
2			2008	0.6364		4.60%		2.93%	25.64	160.00	
3			2009	0.3440		5.20%		1.79%	22.91	174.63	
4			2010	0.4379		6.50%		2.85%	23.59	175.00	
5			2011	0.4709		7.20%		3.39%	24.14	175.66	
6			GROWTH 2007 - 2011					2.74%	-		2.36%
7			2012	0.5826		8.50%		4.95%		177.00	0.76%
8			2013	0.5378		8.50%		4.57%		180.00	1.23%
9			2015-17	0.5000		9.00%		4.50%	2.50%	188.00	1.37%
10											
11	AWR	AMERICAN STATES WATER CO.	2007	0.4074		9.30%		3.79%	17.53	17.23	
12			2008	0.3548		8.60%		3.05%	17.95	17.30	
13			2009	0.3765		8.20%		3.09%	19.39	18.53	
14			2010	0.5315		11.00%		5.85%	20.26	18.63	
15			2011	0.5089		10.30%		5.24%	21.68	18.85	
16			GROWTH 2007 - 2011					4.20%	5.00%		2.27%
17			2012	0.5208		10.50%		5.47%		19.00	0.80%
18			2013	0.4630		11.00%		5.09%		19.20	0.92%
19			2015-17	0.4286		12.00%		5.14%	2.50%	19.60	0.78%
20											
21	CWT	CALIFORNIA WATER SERVICE GROUP	2007	0.2267		8.10%		1.84%	9.25	41.33	
22			2008	0.3789		9.90%		3.75%	9.72	41.45	
23			2009	0.3980		9.60%		3.82%	10.13	41.53	
24			2010	0.3407		8.60%		2.93%	10.45	41.67	
25			2011	0.2791		8.00%		2.23%	10.76	41.82	
26			GROWTH 2007 - 2011					2.91%	5.00%		0.30%
27			2012	0.3505		8.50%		2.98%		42.25	1.03%
28			2013	0.3905		9.00%		3.51%		44.00	2.57%
29			2015-17	0.4462		10.50%		4.68%	3.50%	47.00	2.36%
30											
31	MSEX	MIDDLESEX WATER COMPANY	2007	0.2069		8.70%		1.80%	10.05	13.25	
32			2008	0.2135		8.90%		1.90%	10.03	13.40	
33			2009	0.0139		7.00%		0.10%	10.33	13.52	
34			2010	0.2500		8.20%		2.05%	11.13	15.57	
35			2011	0.1310		7.60%		1.00%	11.27	15.70	
36			GROWTH 2007 - 2011					1.37%	5.50%		4.33%
37			2012	0.1778		7.50%		1.33%		16.00	1.91%
38			2013	0.2500		8.00%		2.00%		16.25	1.74%
39			2015-17	0.3600		9.00%		3.24%	3.50%	17.25	1.90%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 01/18/2013
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2007 - 2011

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, 2011
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	SJW	SJW CORPORATION	2007	0.4135		8.20%		3.39%	12.90	18.36	
2			2008	0.3981		8.00%		3.19%	13.99	18.18	
3			2009	0.1852		6.00%		1.11%	13.66	18.50	
4			2010	0.1905		6.20%		1.18%	13.75	18.55	
5			2011	0.3784		7.90%		2.99%	14.20	18.59	
6			GROWTH 2007 - 2011					2.37%	4.50%		0.31%
7			2012	0.3238		7.00%		2.27%		18.75	0.86%
8			2013	0.3917		7.50%		2.94%		20.00	3.72%
9			2015-17	0.4483		7.00%		3.14%	3.50%	22.00	3.43%
10											
11	WTR	AQUA AMERICA, INC.	2007	0.3239		9.70%		3.14%	7.32	133.40	
12			2008	0.3014		9.30%		2.80%	7.82	135.37	
13			2009	0.2857		9.40%		2.69%	8.12	136.49	
14			2010	0.3444		10.60%		3.65%	8.51	137.97	
15			2011	0.3981		11.40%		4.54%	9.01	138.87	
16			GROWTH 2007 - 2011					3.36%	7.00%		1.01%
17			2012	0.3619		11.00%		3.98%		140.90	1.46%
18			2013	0.3826		11.50%		4.40%		141.90	1.09%
19			2015-17	0.4074		12.50%		5.09%	4.00%	143.90	0.71%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 01/18/2013
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, & 16, SIMPLE AVERAGE GROWTH, 2007 - 2011

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINE 6, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

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	AGL RESOURCES, INC.	2007	0.3971		5.04%		5.04%	21.74	76.40	
2			2008	0.3801		4.79%		4.79%	21.48	76.90	
3			2009	0.4028		5.03%		5.03%	22.95	77.54	
4			2010	0.4133		5.33%		5.33%	23.24	78.00	
5			2011	0.1038		0.54%		0.54%	28.54	117.00	
6			GROWTH 2007 - 2011					4.15%	5.50%		11.24%
7			2012	0.3556		1.07%		1.07%		117.00	0.00%
8			2013	0.4250		1.91%		1.91%		117.00	0.00%
9			2015-17	0.4842		2.66%		2.66%	5.00%	117.00	0.00%
10											
11	ATO	ATMOS ENERGY CORP.	2007	0.3402		2.96%		2.96%	22.01	89.33	
12			2008	0.3500		3.08%		3.08%	22.60	90.81	
13			2009	0.3299		2.74%		2.74%	23.52	92.55	
14			2010	0.3796		3.49%		3.49%	24.16	90.16	
15			2011	0.3982		3.50%		3.50%	24.98	90.30	
16			GROWTH 2007 - 2011					3.16%	4.50%		0.27%
17			2012	0.3429		2.74%		2.74%		90.00	-0.33%
18			2013	0.4043		3.23%		3.23%		91.00	0.39%
19			2015-17	0.4519		3.61%		3.61%	6.00%	103.00	2.67%
20											
21	LG	LACLEDE GROUP, INC.	2007	0.3723		4.32%		4.32%	19.79	21.65	
22			2008	0.4356		5.14%		5.14%	22.12	21.99	
23			2009	0.4760		5.90%		5.90%	23.32	22.17	
24			2010	0.3539		3.57%		3.57%	24.02	22.29	
25			2011	0.4371		4.85%		4.85%	25.56	22.43	
26			GROWTH 2007 - 2011					4.76%	6.50%		0.89%
27			2012	0.4050		4.29%		4.29%		22.62	0.85%
28			2013	0.3895		3.70%		3.70%		23.00	1.26%
29			2015-17	0.4424		4.42%		4.42%	4.50%	23.50	0.94%
30											
31	NJR	NEW JERSEY RESOURCES CORPORATION	2007	0.3484		3.52%		3.52%	15.50	41.61	
32			2008	0.5889		9.25%		9.25%	17.28	42.06	
33			2009	0.4833		7.06%		7.06%	16.59	41.59	
34			2010	0.4472		6.26%		6.26%	17.62	41.17	
35			2011	0.4419		6.05%		6.05%	18.73	41.45	
36			GROWTH 2007 - 2011					6.43%	7.50%		-0.10%
37			2012	0.4391		6.15%		6.15%		41.53	0.19%
38			2013	0.4483		7.17%		7.17%		40.00	-1.76%
39			2015-17	0.5059		7.08%		7.08%	5.50%	40.00	-0.71%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 12/07/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2007 - 2011

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, 2011
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	NWN	NORTHWEST NATURAL GAS CO.	2007	0.4783		5.98%		5.98%	22.52	26.41	
2			2008	0.4086		4.45%		4.45%	23.71	26.50	
3			2009	0.4346		4.95%		4.95%	24.88	26.53	
4			2010	0.3846		4.04%		4.04%	26.08	26.58	
5			2011	0.2678		2.38%		2.38%	26.70	26.76	
6			GROWTH 2007 - 2011					4.36%	4.00%		0.33%
7			2012	0.2044		1.74%		1.74%		27.00	0.90%
8			2013	0.2531		2.28%		2.28%		27.50	1.37%
9			2015-17	0.3778		4.34%		4.34%	1.00%	28.00	0.91%
10											
11	PNY	PIEDMONT NATURAL GAS COMPANY	2007	0.2929		3.49%		3.49%	11.99	73.23	
12			2008	0.3087		3.83%		3.83%	12.11	73.26	
13			2009	0.3593		4.74%		4.74%	12.67	73.27	
14			2010	0.2839		3.29%		3.29%	13.35	72.28	
15			2011	0.2675		3.05%		3.05%	13.79	72.32	
16			GROWTH 2007 - 2011					3.68%	3.00%		-0.31%
17			2012	0.2563		2.95%		2.95%		71.00	-1.83%
18			2013	0.2765		3.32%		3.32%		70.00	-1.62%
19			2015-17	0.2703		3.38%		3.38%	1.50%	68.00	-1.22%
20											
21	SJI	SOUTH JERSEY INDUSTRIES, INC.	2007	0.5167		6.61%		6.61%	16.25	29.61	
22			2008	0.5110		6.69%		6.69%	17.33	29.73	
23			2009	0.4874		6.38%		6.38%	18.24	29.80	
24			2010	0.4963		7.05%		7.05%	19.08	29.87	
25			2011	0.4810		6.69%		6.69%	20.66	30.21	
26			GROWTH 2007 - 2011					6.69%	7.00%		0.50%
27			2012	0.4762		6.67%		6.67%		31.50	4.27%
28			2013	0.4567		5.94%		5.94%		32.50	3.72%
29			2015-17	0.4889		7.82%		7.82%	6.00%	36.00	3.57%
30											
31	SWX	SOUTHWEST GAS CORPORATION	2007	0.5590		4.75%		4.75%	22.98	42.81	
32			2008	0.3525		2.08%		2.08%	23.49	44.19	
33			2009	0.5103		4.03%		4.03%	24.44	45.09	
34			2010	0.5595		4.98%		4.98%	25.62	45.56	
35			2011	0.5638		5.19%		5.19%	26.66	45.96	
36			GROWTH 2007 - 2011					4.21%	5.00%		1.79%
37			2012	0.5662		5.38%		5.38%		46.50	1.17%
38			2013	0.5439		5.17%		5.17%		47.00	1.13%
39			2015-17	0.5733		6.02%		6.02%	6.00%	50.00	1.70%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 12/07/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2007 - 2011

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, 2011
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	WGL	WGL HOLDINGS, INC.	2007	0.3445		3.58%		3.58%	19.83	49.45	
2			2008	0.4221		4.39%		4.39%	20.99	49.92	
3			2009	0.4190		4.86%		4.86%	21.89	50.14	
4			2010	0.3392		3.36%		3.36%	22.82	50.54	
5			2011	0.3111		2.96%		2.96%	23.49	51.20	
6			GROWTH 2007 - 2011					3.83%	5.00%		0.87%
7			2012	0.4067		4.47%		4.47%		51.50	0.59%
8			2013	0.3480		3.48%		3.48%		51.75	0.54%
9			2015-17	0.3636		3.45%		3.45%	4.00%	52.00	0.31%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 12/07/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINE 6, SIMPLE AVERAGE GROWTH, 2007 - 2011

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINE 6, 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, 2011
GROWTH RATE COMPARISON

DOCKET NO. W-01445A-12-0348
SCHEDULE WAR - 6

WATER COMPANY SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	AWK	4.85%	8.50%	9.00%	6.50%	2.50%	-	-	-	6.63%	-	-	-3.97%
2	AWR	5.66%	6.00%	5.50%	7.50%	2.50%	11.50%	2.50%	5.00%	5.79%	8.44%	3.46%	5.46%
3	CWT	5.32%	5.00%	6.00%	3.00%	3.50%	5.00%	1.00%	5.00%	4.07%	3.48%	1.68%	3.85%
4	MSEX	3.59%	-	7.00%	1.50%	3.50%	4.50%	1.50%	5.50%	3.92%	-0.87%	1.42%	2.91%
5	SJW	4.23%	-	8.00%	3.00%	3.50%	-3.00%	5.00%	4.50%	3.50%	1.64%	3.13%	2.43%
6	WTR	5.77%	6.90%	7.00%	5.00%	4.00%	4.50%	8.00%	7.00%	6.06%	9.75%	6.61%	5.33%
7				7.08%	4.42%	3.25%	4.50%	3.60%	5.40%		4.49%	3.26%	2.67%
8	AVERAGES	4.90%	6.60%		4.92%			4.50%		4.99%		3.47%	

NATURAL GAS LDC SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	GAS	2.00%	4.30%	6.00%	1.50%	5.00%	4.50%	7.50%	5.50%	4.90%	-6.04%	3.75%	7.04%
2	ATO	3.98%	4.30%	4.00%	1.50%	6.00%	4.00%	1.50%	4.50%	3.69%	3.89%	1.53%	3.22%
3	LG	4.13%	3.00%	3.00%	2.50%	4.50%	6.00%	2.50%	6.50%	4.00%	5.48%	2.65%	6.61%
4	NJR	7.01%	4.00%	5.50%	4.00%	5.50%	7.00%	8.00%	7.50%	5.93%	13.59%	9.27%	4.85%
5	NWN	4.29%	4.20%	3.00%	2.50%	1.00%	4.50%	4.50%	4.00%	3.39%	-3.53%	5.00%	4.35%
6	PNY	3.01%	3.70%	2.50%	3.50%	1.50%	4.50%	4.00%	3.00%	3.24%	2.91%	3.82%	3.56%
7	SJI	9.65%	6.00%	9.00%	9.00%	6.00%	7.00%	9.50%	7.00%	7.64%	8.44%	10.39%	6.19%
8	SWX	6.40%	5.00%	9.00%	8.00%	6.00%	6.50%	4.00%	5.00%	6.21%	5.66%	5.37%	3.78%
9	WGL	3.68%	5.30%	2.50%	2.50%	4.00%	3.00%	2.50%	5.00%	3.54%	1.86%	3.13%	4.33%
10				4.94%	3.89%	4.39%	5.22%	4.89%	5.33%		3.58%	4.99%	4.88%
11	AVERAGES	4.90%	4.42%		4.41%			5.15%		4.73%		4.48%	

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 01/18/2013 (WATER COMPANIES) AND 12/07/2012 (NATURAL GAS LDC's)
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 01/18/2013 (WATER COMPANIES) AND 12/07/2012 (NATURAL GAS LDC's)
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THRU 3 (WATER) AND 1 THRU 9 (NATURAL GAS)
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 01/18/2013 (WATER COMPANIES) AND 12/07/2012 (NATURAL GAS LDC's)

ARIZONA WATER COMPANY
DOCKET NO. W-01445A-12-0348
CAPM COST OF EQUITY CAPITAL

DOCKET NO. W-01445A-12-0348
SCHEDULE WAR - 6
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	AWK	k	=	2.95%	+ [	0.65	x (	9.80%	-	5.70%	)] =	5.62%
2	AWR	k	=	2.95%	+ [	0.70	x (	9.80%	-	5.70%	)] =	5.82%
3	CWT	k	=	2.95%	+ [	0.65	x (	9.80%	-	5.70%	)] =	5.62%
4	MSEX	k	=	2.95%	+ [	0.70	x (	9.80%	-	5.70%	)] =	5.82%
5	SJW	k	=	2.95%	+ [	0.85	x (	9.80%	-	5.70%	)] =	6.44%
6	WTR	k	=	2.95%	+ [	0.60	x (	9.80%	-	5.70%	)] =	5.41%
7	**WATER COMPANY AVERAGE**					0.69						**5.79%**
8	GAS	k	=	2.95%	+ [	0.75	x (	9.80%	-	5.70%	)] =	6.03%
9	ATO	k	=	2.95%	+ [	0.70	x (	9.80%	-	5.70%	)] =	5.82%
10	LG	k	=	2.95%	+ [	0.55	x (	9.80%	-	5.70%	)] =	5.21%
11	NJR	k	=	2.95%	+ [	0.65	x (	9.80%	-	5.70%	)] =	5.62%
12	NWN	k	=	2.95%	+ [	0.55	x (	9.80%	-	5.70%	)] =	5.21%
13	PNY	k	=	2.95%	+ [	0.65	x (	9.80%	-	5.70%	)] =	5.62%
14	SJI	k	=	2.95%	+ [	0.65	x (	9.80%	-	5.70%	)] =	5.62%
15	SWX	k	=	2.95%	+ [	0.75	x (	9.80%	-	5.70%	)] =	6.03%
16	WGL	k	=	2.95%	+ [	0.65	x (	9.80%	-	5.70%	)] =	5.62%
17	**NATURAL GAS LDC AVERAGE**					0.66						**5.64%**

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)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 30-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 12/07/2012 THROUGH 01/25/2013 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 - 2011 PERIOD MINUS TOTAL RETURNS ON LONG-TERM TREASURIES DURING THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2012 YEARBOOK.

ARIZONA WATER COMPANY
DOCKET NO. W-01445A-12-0348
CAPM COST OF EQUITY CAPITAL

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+	[	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AWK	k	=	2.95%	+	[	0.65	x	(	11.80%	-	6.10%	)]	=	6.66%
2	AWR	k	=	2.95%	+	[	0.70	x	(	11.80%	-	6.10%	)]	=	6.94%
3	CWT	k	=	2.95%	+	[	0.65	x	(	11.80%	-	6.10%	)]	=	6.66%
4	MSEX	k	=	2.95%	+	[	0.70	x	(	11.80%	-	6.10%	)]	=	6.94%
5	SJW	k	=	2.95%	+	[	0.85	x	(	11.80%	-	6.10%	)]	=	7.80%
6	WTR	k	=	2.95%	+	[	0.60	x	(	11.80%	-	6.10%	)]	=	6.37%
7	WATER COMPANY AVERAGE						0.69								6.90%
8	GAS	k	=	2.95%	+	[	0.75	x	(	11.80%	-	6.10%	)]	=	7.23%
9	ATO	k	=	2.95%	+	[	0.70	x	(	11.80%	-	6.10%	)]	=	6.94%
10	LG	k	=	2.95%	+	[	0.55	x	(	11.80%	-	6.10%	)]	=	6.09%
11	NJR	k	=	2.95%	+	[	0.65	x	(	11.80%	-	6.10%	)]	=	6.66%
12	NWN	k	=	2.95%	+	[	0.55	x	(	11.80%	-	6.10%	)]	=	6.09%
13	PNY	k	=	2.95%	+	[	0.65	x	(	11.80%	-	6.10%	)]	=	6.66%
14	SJI	k	=	2.95%	+	[	0.65	x	(	11.80%	-	6.10%	)]	=	6.66%
15	SWX	k	=	2.95%	+	[	0.75	x	(	11.80%	-	6.10%	)]	=	7.23%
16	WGL	k	=	2.95%	+	[	0.65	x	(	11.80%	-	6.10%	)]	=	6.66%
17	NATURAL GAS LDC AVERAGE						0.66								6.69%

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)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 30-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 12/07/2012 THROUGH 01/25/2013 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 - 2011 PERIOD MINUS TOTAL RETURNS ON LONG-TERM TREASURIES DURING THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2012 YEARBOOK.

ARIZONA WATER COMPANY
DOCKET NO. W-01445A-12-0348
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. W-01445A-12-0348
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%	2.90%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.84%	-6.80%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	2009	-0.36%	5.00%	3.25%	0.50%	0.00% - 0.25%	0.15%	4.08%	5.84%	6.87%
21	2010	1.64%	2.80%	3.25%	0.72%	0.00% - 0.25%	0.13%	4.25%	5.50%	5.98%
22	2011	3.00%	1.70%	3.25%	0.75%	0.00% - 0.25%	0.05%	3.93%	5.06%	5.58%
23	2012	1.70%	2.20%	3.25%	0.75%	0.00% - 0.25%	0.08%	2.92%	3.99%	4.42%
24	CURRENT	1.70%	2.20%	3.25%	0.75%	0.00% - 0.25%	0.05%	3.10%	4.00%	4.36%

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
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 01/18/2013
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 01/18/2013
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

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TEST YEAR ENDED DECEMBER 31, 2011
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. W-01445A-12-0348
SCHEDULE WAR - 9

AVERAGE CAPITAL STRUCTURES OF SAMPLE WATER COMPANIES (000's)

LINE NO.		AWK	PCT.	AWR	PCT.	CWT	PCT.	SJW	PCT.	MSEX	PCT.
1	DEBT	$ 5,339.9	55.6%	$ 340.6	45.5%	$ 479.2	52.4%	$ 343.8	56.6%	$ 132.2	42.3%
2											
3	PREFERRED STOCK	25.7	0.3%	0.0	0.0%	0.0	0.0%	0.0	0.0%	3.3	1.1%
4											
5	COMMON EQUITY	4,235.8	44.1%	408.6	54.5%	435.5	47.6%	264.0	43.4%	177.0	56.6%
6											
7	TOTALS	$ 9,601.4	100%	$ 749.2	100%	$ 914.7	100%	$ 607.8	100%	$ 312.5	100%

LINE NO.		WTR	PCT.	WATER COMPANY AVERAGE	PCT.
8					
9					
10					
11					
12	DEBT	$ 1,395.4	52.7%	$ 1,338.5	54.1%
13					
14	PREFERRED STOCK	0.0	0.0%	4.8	0.2%
15					
16	COMMON EQUITY	1,251.8	47.3%	1,128.8	45.7%
17					
18	TOTALS	$ 2,647.2	100%	$ 2,472.1	100%

AVERAGE CAPITAL STRUCTURES OF SAMPLE NATURAL GAS COMPANIES (000's)

LINE NO.		AGL	PCT.	ATO	PCT.	LG	PCT.	NJR	PCT.	NWN	PCT.
1											
2											
3	DEBT	$ 3,561.0	51.6%	$ 1,956.3	45.3%	$ 339.4	40.9%	$ 525.1	39.2%	$ 641.7	47.3%
4											
5	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
6											
7	COMMON EQUITY	3,339.0	48.4%	2,359.2	54.7%	491.3	59.1%	813.9	60.8%	714.5	52.7%
8											
9	TOTALS	$ 6,900.0	100%	$ 4,315.5	100%	$ 830.7	100%	$ 1,339.0	100%	$ 1,356.2	100%

LINE NO.		PNY	PCT.	SJI	PCT.	SWX	PCT.	WGL	PCT.	NATURAL GAS LDC AVERAGE	PCT.
10											
11											
12											
13											
14	DEBT	$ 675.0	40.4%	$ 424.2	40.5%	$ 930.8	43.2%	$ 589.2	31.2%	$ 1,071.4	44.8%
15											
16	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	28.2	1.5%	$ 3.1	0.1%
17											
18	COMMON EQUITY	996.9	59.6%	624.1	59.5%	1,225.0	56.8%	1,269.5	67.3%	1,314.8	55.0%
19											
20	TOTALS	$ 1,671.9	100%	$ 1,048.3	100%	$ 2,155.8	100%	$1,886.9	100%	$ 2,389.4	100%

LINE NO.		WATER & LDC AVERAGE	PCT.
21			
22			
23			
24			
25	DEBT	$ 1,205.0	49.6%
26			
27	PREFERRED STOCK	1.6	0.1%
28			
29	COMMON EQUITY	1,221.8	50.3%
30			
31	TOTALS	$ 2,428.3	100%

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS