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Transcript Exhibit(s)

Docket #(s): G-04204A-08-0571

Exhibit # : IBEW1 $ IBEW2, Mayes1- Mayes2, RUCO1-RUCO21

Arizona Corporation Commission
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To: Docket Control

Date: August 25, 2009

Re: UNS Gas / Rates
G-04204A-08-0571
August 10 through August 25, 2009
Volumes I through VI Concluded

STATUS OF ORIGINAL EXHIBITS

FILED WITH DOCKET CONTROL

IBEW LOCAL 1116 (IBEW Exhibits)

1 and 2

MAYES (MAYES Exhibits)

1 and 2

RUCO (RUCO Exhibits)

1 through 21

STAFF (S Exhibits)

1 through 4, 6 through 15

UNS GAS (UNSG Exhibits)

1 through 46

ZWICK (Z Exhibits)

1 through 3

EXHIBITS GIVEN TO ACALJ NODES CONFIDENTIAL

RUCO (RUCO Exhibits)

22, 23

STAFF (S Exhibits)

5

Copy to:

Dwight D. Nodes, ACALJ
Robin Mitchell, Esq. - Staff
Philip J. Dion, III, Esq. - UNS
Daniel Pozefsky, Esq. - RUCO

COPY

EXHIBIT
IBEW-1
ADMITTED

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Attorneys for Intervenor IBEW Local 1116

BEFORE THE ARIZONA

CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. G-04204A-08-0105 **NOTICE OF FILING DIRECT TESTIMONY OF FRANK GRIJALVA**

Pursuant to the Administrative Law Judge's Procedural Order (p. 2) dated January 7, 2009, Local Union 1116, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 1116"), by and through undersigned counsel, hereby provides notice of its filing of the attached Direct Testimony of Frank Grijalva in this docket.

RESPECTFULLY SUBMITTED this 8th day of June 2009.

LUBIN & ENOCH, P.C.

Nicholas J. Enoch, Esq.
Attorney for Intervenor

Original and thirteen (13) copies of IBEW Local 1116's Notice filed this 8th day of June, 2009, with:

Arizona Corporation Commission
Docket Control Center
1200 West Washington Street
Phoenix, Arizona 85007-2996

Copies of the foregoing transmitted electronically this same date to:

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Hearing Division
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Phoenix, Arizona 85007

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Intervenor

Michael Green

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Frank Grijalva. My business address is 750 South Tucson Boulevard, Tucson, Arizona 85716-5689.

Q2. PLEASE DESCRIBE YOUR RECENT EMPLOYMENT.

A2. I am the Business Manager/Financial Secretary for Intervenor Local Union 1116, International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 1116"). The position of Business Manager/Financial Secretary is an elected union position and, due to the retirement of my predecessor, I was appointed by our Executive Board to my present position in October 2007. Because all IBEW local unions also have a person holding the position of "President," it is common for persons outside of our organization to believe that the "President" is the principal officer of the Local. That is not the case. Article 17, §§ 4 and 8 of the Constitution of the International Brotherhood of Electrical Workers, AFL-CIO, clearly states that the Business Manager/Financial Secretary is the "principal officer" of any IBEW local union.

Prior to my becoming Business Manager/Financial Secretary for IBEW Local 1116, I was employed by the Tucson Electric Power Company ("TEP") for twenty-two (22) years in a variety of bargaining unit positions, the last of which was as a Designer for Transmission and Distribution Construction. While employed at TEP, I was a very active member of IBEW Local 1116, including previously serving as the Local's President and in other positions on the Executive Board.

Q3. WHAT IS IBEW LOCAL 1116?

A3. IBEW Local 1116 is the labor organization which serves as the exclusive representative for, *inter alia*, approximately one-hundred and ten (110) employees of UNS Gas. In particular, IBEW Local 1116 represents all of the UNS Gas employees holding the following positions:

- Construction and Maintenance Crewman,
- Customer Service Representative (I & II),
- Dispatcher,
- Material Control Technician,
- Meter Reader,
- Planner,
- Service Technician, and
- Utilityperson.

IBEW Local 1116 and UNS Gas have entered two collective bargaining agreements dating back to June of 2004 concerning rates of pay, wages, hours of employment, and other terms and conditions of employment.

In addition to representing the aforementioned employees at UNS Gas, IBEW Local 1116 also represents hundreds of employees at TEP [a UniSource Energy Corporation ("UniSource") company], Southwest Energy Solutions (also a UniSource company), Trico Electric Cooperative, Inc. ("Trico") and Asplundh Tree Expert Company. To learn more about IBEW Local 1116, I invite you to visit our website at www.ibew1116.com.

Q4. HAVE YOU TESTIFIED IN OTHER MATTERS BEFORE THE ARIZONA CORPORATION COMMISSION?

A4. Yes. On behalf of IBEW Local 1116, I testified in support of the 2008 TEP settlement agreement. *See generally* 2008 Ariz. PUC LEXIS 201. Just last month, I testified in support of Trico's pending rate application, Docket No. E-01461A-08-0430. As my union firmly believes that our success is inextricably linked to the success of our represented companies, we are always willing to voice our public support for them when it is justified, like in this case, and when it is in our mutually-beneficial interest to do so.

Q5. DO YOU BELIEVE UNS GAS IS A RESPONSIBLE CORPORATE CITIZEN?

A5. Absolutely. While by no means perfect, the relationship between IBEW Local 1116 and TEP is one which is mature and stable. It is clear that this stability has benefitted UNS Gas, its employees, and customers. In my opinion, the importance of the strong and stable relationship between a public service corporation and its employees cannot be overstated. I believe that my opinion in this regard is widely shared.

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A6. As you know, Article XV, §3 of the Arizona Constitution expressly states that the interests of public service employees are on par with those of patrons. It reads as follows:

> The corporation commission shall have full power to, and shall ... make reasonable

> rules, regulations, and orders, by which such [public service] corporations shall be governed in the transaction of business within the State, and ... make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the preservation of the health, of the ***employees*** and patrons of such corporations[.]

On behalf of its own members, as well as thousands patrons of UNS Gas, IBEW Local 1116 believes this proceeding provides it with a unique and timely opportunity to express to this Commission our qualified support of UNS Gas's Application and our reasons for doing so.

Q7. DO YOU BELIEVE THAT UNS GAS IS ENTITLED TO AN INCREASE ITS RATES EFFECTIVE NO LATER THAN DECEMBER 1, 2009?

A7. Yes.

Q8. PLEASE EXPLAIN WHAT YOU MEAN BY "THE INCOME TRANSFER FUNCTION OF RATEMAKING."

A8. At the most generalized level, ratemaking distributes wealth from consumers to utility owners. Thus, one function of ratemaking is to affect the amount of money that is transferred from ratepayers to the shareholders that own the utility. In other words, ratemaking is not only a form of price control, it is also a form of profit control. I will refer to this dynamic as the "the income transfer function of ratemaking."

Q9. WHAT DO YOU BELIEVE OUGHT TO BE DONE WITH UNS GAS'S PAYROLL

EXPENSE ADJUSTMENT AND PAYROLL TAX EXPENSE ADJUSTMENT?

A9. On page 19, lines 20-25, of Dallas Dukes' Direct Testimony, a reference is made to an "estimated pay rate increase that will go into effect January 1, 2010" and that "[t]he pay rate increase as of January 1, 2010, will be known prior to the close of the record in this proceeding and prior to rates going into effect based on a decision in this proceeding." Because UNS Gas and IBEW Local 1116 just recently concluded their contract negotiations regarding, *inter alia*, the year 2010, this should assist the Company in making any adjustments that may need to be made to the Payroll Expense and Payrolls Tax Expense adjustments. In particular, if the contractually agreed-upon pay increase is greater than the estimate set forth in the Application, then Gas ought to seek, and IBEW Local 1116 would fully support, a corresponding increase to the Payroll Expense and Payroll Tax Expense adjustments.

I know that Dallas Dukes believes that "the rate can be updated if its varies ***significantly*** from the estimate" but, in my opinion, it ought to be updated irrespective of the size of the discrepancy. Otherwise, public service corporations, like UNS Gas, would not be allowed to recuperate their actual increases in the cost of doing business.

Q10. **DO YOU BELIEVE THAT UNS GAS OUGHT TO RECOVER A GREATER SHARE OF ITS FIXED COSTS THROUGH A HIGHER FIXED MONTHLY SERVICE CHARGE?**

A10. Yes.

Q11. DOES THIS CONCLUDE YOUR TESTIMONY?

A11. Yes.

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EXHIBIT
IBEW - 2
ADMITTED

Under the Agreement, TEP would be precluded from issuing dividends to UniSource in an amount that comprises more than 75 percent of TEP's earnings, until such time as TEP's equity capitalization reaches 40 percent of total capital. In addition, until ElecCo's and GasCo's respective equity capitalization equals 40 percent of total capital, they will not issue dividends to HoldCo or UniSource in an amount that comprises more than 75 percent of ElecCo's or GasCo's earnings.

We find the capital structure provisions of the Stipulation properly balance UniSource's need for financing flexibility with the need to maintain the financial health of regulated utilities. As Staff points out, the Agreement's capital structure incentives are based on conditions imposed by prior Commission Orders that have helped TEP dramatically improve its debt/equity ratio. We believe the Settlement's imposition of similar controls for ElecCo and GasCo will help ensure that the new electric and gas utilities formed by UniSource will achieve an appropriate mix of debt and equity consistent with financially healthy utility companies.

L. <u>Pipeline Safety Provisions</u>

The Settlement contains a number of provisions related to maintaining gas pipeline safety. Among those terms are the following: (1) UniSource will not allow the acquisition to diminish staffing that would result in service and/or safety degradation in the NAGD or SCGD service areas; (2) UniSource will continue to maintain fully operational current local field offices in the NAGD and SCGD services areas to maintain quality of service and ensure pipeline safety; (3) UniSource will continue Citizens' current practice of not using contract personnel for performance of operation and maintenance functions such as leak surveys and valve maintenance; (4) UniSource will adopt the most recent version of Citizens' operation and maintenance manuals and procedures, including Citizens' emergency plan, and will make revisions and updates only as necessary, with such revisions or updates to be provided to the Commission's Chief of the Office of Pipeline safety; (5) UniSource will make all reasonable efforts to prevent degradation in the quality of service to current Citizens gas customers; and (6) GasCo will independently inspect all work done by contract personnel regarding installation of new service lines and main extensions.

No party opposed these provisions of the Stipulation and we find that they are reasonable terms to ensure that UniSource's operations will adhere to gas pipeline safety requirements.

Midwest Energy, Inc.

Making Energy Work For You

How$mart℠

Now you can make efficiency improvements and reduce your Midwest Energy bill at the same time, often without an up-front capital investment. You don't even need to own the property! How$mart℠ provides money for energy efficiency improvements such as insulation, air sealing and new heating and cooling systems. Participating customers repay the funds through energy savings on their monthly Midwest Energy bills.

How$mart℠ program features:

- No up-front capital is required for qualifying investments. (Customers have the option of "buying-down" the cost of non-economic improvements when the projected savings will not cover the entire cost.)
- Monthly How$mart℠ surcharge covers the cost of qualifying improvements. The surcharge is always less than the projected savings.
- The How$mart℠ surcharge is tied to the location. If you move or sell the property, the next customer pays the surcharge. (Full disclosure to subsequent customers is required.)

Participating customers must start with an energy audit to determine potential savings. Midwest Energy will develop a conservation plan with recommended improvements. Customers may choose the contractor to complete the work. (Contractors must sign a Contractor Master Agreement, and tenants must have the written consent of their landlord.)

How$mart℠ is available to all Midwest Energy residential and small commercial customers. Contact Kay Unruh at 800-222-3121 or 785-625-1474 to obtain complete program details or to start your How$mart℠ project.

How$smart℠ Brochure

Current Participating Contractors

Frequently asked How$mart℠ Questions

Midwest Energy is a customer-owned electric and natural gas utility located in central and western Kansas.
We serve 48,000 electric and 42,000 natural gas customers.
 1330 Canterbury Hays, Kansas 67601 **800-222-3121**

Improve Your Home's Energy Efficiency With . . . How$mart[SM]

- **WHAT IS How$mart[SM]?**

  How$mart[SM] is a program that provides money for energy efficiency improvements such as insulation, sealing and heating and cooling systems. Customers will repay the funds through energy savings on their monthly utility bill. The monthly surcharge will be less than the amount of savings.

- **HOW MUCH ENERGY CAN BE SAVED?**

  A Midwest Energy Specialist will perform an audit to identify potential savings opportunities. The repayment surcharge will be no more than 90% of the projected savings. If there is a change in owner or tenant, the surcharge remains with the improved property.

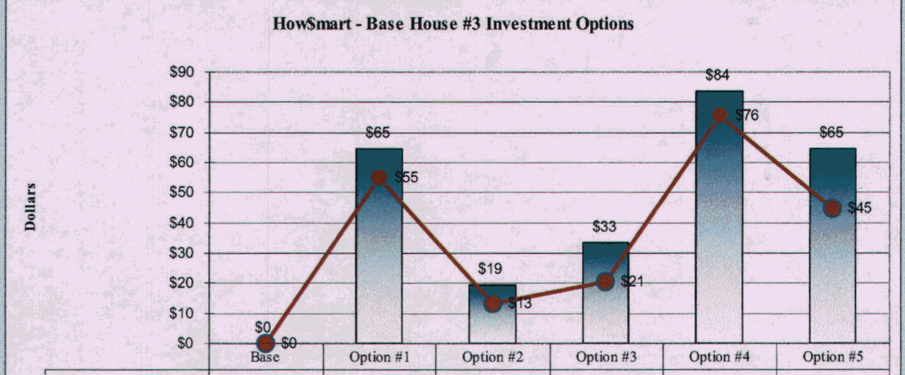
- **WHO CAN USE THIS PROGRAM?**

  The program is available to Midwest Energy electric and/or gas customers in good standing. It is particularly attractive to landlords and tenants to improve energy efficiency and lower utility bills with no up front investment.

For More Information on Midwest Energy Services:
www.mwenergy.com/energyservices.aspx

Midwest Energy is the first utility in the nation to voluntarily adopt a program like How$mart[SM]. How$mart[SM] provides money for energy efficiency improvements such as insulation, sealing and heating and cooling systems to customers who will repay the funds through energy savings on their monthly utility bill.

Example of Insulated Base House Monthly Savings compared to Monthly How$mart Surcharge.



	Base	Option #1	Option #2	Option #3	Option #4	Option #5
Monthly Savings	$0	$65	$19	$33	$84	$65
Monthly Surcharge	$0	$55	$13	$21	$76	$45

2400 sq ft, R-7 Attic, 0 Wall Insulation, High Air Leakage, 64% Furnace, 6 SEER A/C

Option 1: New 92% Furnace/14 SEER AC at **$5,500**
Option 2: R-38 Attic Insulation at **$1,320**
Option 3: R-38 Attic, Air Sealing at **$2,070**
Option 4: All Measures at **$7,570**
Option 5: Option #1 with $1,000 down payment from Owner

EXHIBIT
tabbies
Mayes2
ADMITTED

FREQUENTLY ASKED QUESTIONS

- **WHAT IS THE FIRST STEP?**
  An energy audit is the first step in making your home more energy efficient. An audit can help you assess how much energy your home uses and evaluate what measures you can take to improve efficiency.
- **WHAT IS INVOLVED IN AN AUDIT?**
  An audit may include duct testing, combustion analysis, blower door tests, infrared scans, insulation inspections, and heating-cooling-ventilation system (HVAC) size calculations.
- **YES, I WANT TO PARTICIPATE IN THE PROGRAM. WHAT IS THE NEXT STEP?**
  The next step is provide bids to Midwest Energy for the recommended improvements.
- **DOES MIDWEST ENERGY RECOMMEND A CONTRACTOR?**
  Midwest Energy does NOT recommend contractors. However, to participate in the program, a How$mart Contractor Master Agreement must be on file with Midwest Energy.
- **WHEN IS THE SURCHARGE APPLIED TO MY MIDWEST ENERGY UTILITY BILL?**
  After the energy improvements have been made and agreements have been signed, Midwest Energy will issue payment and add the surcharge to the utility bill.

For more How$mart℠ information:
http://www.mwenergy.com/custresources.aspx

Midwest Energy, Inc.
P.O. Box 898
Hays, Kansas 67601-0898

Improve Your Home's Energy Efficiency with How$mart℠

Midwest Energy, Inc.
"Making Energy Work For You"
1-800-222-3121

EXHIBIT RUCO-1 ADMITTED

UNS GAS, INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 July 22, 2009

RUCO 11.32 Refer to Mr. Dukes' rebuttal testimony at page 5.

a. Admit that UNSG's proposal to fail to offset rate base by the full amount of Customer Advances is simply inconsistent with prior Commission decisions, including, but not limited to, Decision No. 70011 in UNSG's last rate case. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

b. Admit that when UNSG receives a Customer Advance in the form of money, it has the use of that non-investor supplied money. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

c. Admit that Customer Advances are a non-investor supplied source of cost-free capital to the Company. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

d. Admit that UNSG does not reduce the CWIP base to which it applies an AFUDC rate by the amount of Customer Advances related to CWIP. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

e. Admit that Commission Rule A.A.C R 14-2-103, Schedule B-1 requires Customer Advances to be subtracted from rate base. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

f. Admit that Commission Rule A.A.C R 14-2-103, Schedule B-1 requires Customer Advances to be subtracted from rate base, without any exception for Customer Advances related to CWIP. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

g. Admit that Customer Advances are non-investor supplied capital when they are received by the utility. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

h. Admit that UNSG does not hold Customer Advances in an escrow account. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

i. Admit that it would be inappropriate for a utility to earn a return on non-investor supplied capital. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

RESPONSE:

a. UNS Gas does not believe that it is inconsistent, as UNS Gas is requesting only the exclusion of the portion of advances already spent as of the end of the test year on plant not included in rate base. The Company is arguing that the portion already spent is not available as zero cost capital as of the end of the test year, and since the plant it was spent upon is not in rate base, it is unfair to the Company to reduce rate base.

b. Yes. UNS Gas has the use until it is invested in the projects it was specifically advanced to fund. UNS Gas has not attempted to exclude any portion of customer advances not yet spent or spent on plant included in rate base.

c. Please see UNS Gas' response to 11.32.b. above.

d. UNS Gas does not reduce CWIP by advances prior to calculating AFUDC.

e. The only suggestion in Rule 103 that Customer Advances should be deducted from rate base is a line in the form schedule B-1. However, that schedule does not expressly address the circumstance where the advance is related to plant that is not yet in rate base. This rule only controls the general filing format of the rate application, not the final ratemaking decision by the Commission. (See e.g. Decision No. 69914 (Sept. 27, 2007) approving non-deduction of certain advances from rate base.) The rule does not -- and should not -- preclude the Commission from exercising judgment and fairness to insure proper matching and equitable treatment of the shareholders' capital investments. Deducting advances from rate base when the advance is related to plant that is not yet in rate base results in a mismatch and is inequitable because the Company is unable to earn a return on all of its investment in plant that is in rate base.

f. Please see UNS Gas' response to 11.32.e. above.

g. Please see UNS Gas' response to 11.32.b. above.

h. UNS Gas does not hold customer advances received in an escrow account.

i. UNS Gas is not requesting any returns on non-investor supplied capital in this proceeding. As the customer advance reduction in rate base is being interpreted by Staff and RUCO – the Company is being unfairly denied a return on investor supplied capital in rate base.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

BEFORE THE ARIZONA CORPORATION

Arizona Corporation Commission
DOCKETED
SEP 27 2007
DOCKETED BY nr

EXHIBIT
RUCO-2

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA-AMERICAN WATER COMPANY FOR APPROVALS ASSOCIATED WITH A TRANSACTION WITH THE MARICOPA COUNTY MUNICIPAL WATER CONSERVATION DISTRICT NUMBER ONE.

DOCKET NO. W-01303A-05-0718

DECISION NO. 69914

OPINION AND ORDER

DATE OF HEARING:	March 2, 2006 (Pre-hearing Conference); August 1, 2006, September 14, 2006 (Procedural Conferences); December 21, 2006 and March 15, 2007 (Pre-hearing Conferences); March 19, 20, 21 and 26, 2007 (Hearing).
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Teena Wolfe
APPEARANCES:	Kristin K. Mayes, Commissioner, Arizona Corporation Commission

Keith A. Layton, Kevin Torrey and Charles Hains, Staff Attorneys, Legal Division, on behalf of the Arizona Corporation Commission's Utilities Division;

Scott Wakefield, Chief Counsel, and Daniel Pozefsky, Staff Counsel, on behalf of the Residential Utility Consumer Office;

Craig A. Marks, CRAIG A. MARKS, P.L.C., on behalf of Arizona-American Water Company;

Michele L. Van Quathem, RYLEY, CARLOCK & APPLEWHITE, P.A., on behalf of Pulte Homes Corporation;

Jeffrey W. Crockett and Bradley S. Carroll, SNELL & WILMER, L.L.P., on behalf of CHI Construction Company, Inc., Courtland Homes, Inc., Taylor Woodrow/Arizona, Inc., and Fulton Homes Corporation;

Franklyn D. Jeans, BEUS GILBERT, P.L.L.C., on behalf of Suburban Land Reserve, Inc. and Fulton Homes Corporation;

Brian J. Schulman and Melissa Goldenberg, GREENBERG TRAURIG, on behalf of Trend Homes;

Derek L. Sorenson, QUARLES BRADY STREICH LANG, on behalf of Westcor/Surprise, L.L.C.; and

Michael W. Patten and Timothy J. Sabo, ROSHKA, DEWULF & PATTEN, P.L.C., on behalf of Maricopa County Municipal Water Conservation District Number One.

BY THE COMMISSION:

I. PROCEDURAL HISTORY

A. INITIAL APPLICATION

On October 11, 2005, Arizona-American Water Company ("Arizona-American" or "Company") filed with the Arizona Corporation Commission ("Commission") the above-captioned application. The application requested certain approvals associated with a transaction with the Company's Agua Fria Water District and the Maricopa County Municipal Water Conservation District Number One ("MWD") in order to enable the Company to obtain treatment of a portion of the Company's Central Arizona Project ("CAP") water allocation at a planned regional water treatment facility. The October 2005 application stated that MWD proposed to construct a regional water-treatment facility known as the White Tanks Regional Water Treatment Facility to treat surface water delivered over CAP facilities. In association with the planned transaction with MWD, the Company requested Commission approval of the issuance of evidence of indebtedness in the amount of approximately $37,414,000 for a 40-year capital lease obligation with an interest rate of 275 basis points over the long-term Treasury Bond rate; approval of the transfer of certain assets to MWD; and approval of proposed increases to and extension of the Company's existing Water Facilities Hook-Up Fee Tariff assessed to new-home construction. In association with the capital lease, the Company also sought Commission approval of its proposed ratemaking treatment and recovery method for capital and operating costs, and a prudence finding.

By Procedural Order issued December 19, 2005, a procedural schedule was set for the processing of the application, which included a hearing on the application, public notice requirements, and intervention deadlines. The Residential Utility Consumer Office ("RUCO") requested and was granted intervention. No other intervention requests were filed at that time. On February 10, 2006, RUCO filed direct testimony on the October 11, 2005 application, and the Commission's Utilities Division Staff ("Staff") filed a Staff Report on the October 11, 2005 application.

On March 2, 2006, at the Pre-Hearing Conference, the Company indicated that issues had arisen between the Company and MWD, and requested that the procedural schedule in this matter be suspended pending their resolution. By Procedural Order issued March 2, 2006, the Company's request to suspend the procedural schedule was granted.

B. REVISED APPLICATION

Following the March 2, 2006, suspension of the procedural schedule, the Company filed several status reports. A Procedural Conference was convened on August 1, 2006. The Company, RUCO and Staff attended and discussed procedural issues related to the processing of the Company's application.

On September 1, 2006, the Company filed a Revised Application in this docket. The Revised Application indicates that the Company plans to construct a White Tanks Regional Water Treatment Facility ("White Tanks Project"), not in association with MWD. The Revised Application requests, for the Company's Agua Fria District, relief in the form of an adjustment to its existing Water Facilities Hook-Up Fee for new home construction. The Revised Application also requests accounting orders related to the planned water treatment facility, and requests that the Company be ordered to make certain associated filings as a part of its previously-ordered 2008 rate case filing for its Agua Fria District.

On October 27, 2006, Staff filed a Staff Report and Staff Recommended Order, recommending approval of the Company's proposed hook-up fee and accounting order as requested in the Revised Application.

Between October 23, 2006 and December 6, 2006, Applications to Intervene in this proceeding were filed by Pulte Homes Corporation ("Pulte"), CHI Construction Company, Inc.

("CHI"), Courtland Homes, Inc. ("Courtland"), Taylor Woodrow/Arizona Inc. ("Taylor Woodrow"), Trend Homes, Inc. ("Trend"), Fulton Homes Corporation ("Fulton"), Suburban Land Reserve, Inc. ("Suburban"), and Westcor/Surprise, LLC ("Westcor/Surprise") (jointly, "Developers").

On November 8, 2006, MWD filed an Application for Leave to Intervene. Initially, the Company opposed MWD's intervention, but withdrew its opposition in its November 29, 2006 Request for Expedited Hearing.

The hearing in this matter convened as scheduled on March 19, 2007, before an authorized Administrative Law Judge of the Commission, and concluded on March 26, 2007. The parties appeared through counsel, presented testimony, and cross-examined witnesses.

Following the hearing, on March 28, 2007, MWD filed Late-Filed Exhibits D-52 and D-53. Arizona-American, Pulte, Trend, CHI, Courtland, Taylor/Woodrow, Fulton, Suburban, Westcor, MWD, RUCO, and Staff filed closing briefs, and Arizona-American, CHI, Courtland, Taylor/Woodrow, Trend, MWD, and RUCO filed reply briefs. On April 30, 2007, Arizona-American filed a Supplement to Reply Brief. The matter was subsequently taken under advisement pending the submission of a Recommended Opinion and Order to the Commission.

II. POSITIONS OF THE PARTIES

A. ARIZONA-AMERICAN

Arizona-American states that continued reliance solely on groundwater in its Agua Fria Water District would be imprudent due to accelerated groundwater level declines, land subsidence, declining well production rates, and the increasing number of wells not meeting Safe Drinking Water Act water quality standards (Revised Application, Exh. A-2 at 3-4). The Regional Water Supply Plan released by WESTCAPS[1] in April 2001 concluded that the area's water suppliers should maximize use of CAP water and other surface water resources, and recommended the construction of regional treatment facilities to treat that water (Exh. A-2 at 4-5).

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[1] According to the mission statement on its website, "WESTCAPS is a coalition of CAP subcontractors most of whom serve drinking water to communities in the west Salt River Valley. WESTCAPS' mission is to develop workable alternatives for its members to provide their customers with a cost effective, sustainable, reliable, and high quality water supply through partnerships and cooperative efforts in regional water resource planning and management, emphasizing CAP utilization" (*See* http://www.westcaps.org/public/default.cfm). The website lists Arizona-American as a member of WESTCAPS, and lists MWD as an advisor to WESTCAPS.

Arizona-American holds a CAP water subcontract for 11,093 acre-feet per year, and has designed the White Tanks Project to treat CAP water for distribution to its customers in its Agua Fria District (*Id.*). The Company has a construction contract in place for construction of the plant (Direct Testimony of Joseph E. Gross, Exh. A-4 at 4) and permitting of Phase I of the plant is essentially complete (Exh. A-2 at 6). The White Tanks Project is designed to treat 13.5 million gallons per day ("MGD") in Phase I(a). It is expandable to 20 MGD in Phase I(b) with the addition of one more treatment-unit train, and eventually the White Tanks Project can accommodate the addition of three additional 20 MGD phases, for a total treatment capacity of 80 MGD at the 45-acre plant site (*Id.* at 5-6). Arizona-American purchased the White Tanks Project site in 2002 after WESTCAPS identified the site for a treatment facility based on its canal location and its proximity to multiple water provider service areas (*Id.* at 5).

Arizona-American's witness testified that the Company has spent more than six million dollars for land acquisition, the completed design, permitting, company labor and overhead, and has spent over ten million dollars on a completed thirteen mile long north-south water transmission main which will deliver treated water from the White Tanks Project to other transmission mains located throughout the Agua Fria District service area (Exh. A-4 at 5). Arizona-American projects that the White Tanks Project will be needed in May 2009 to meet expected customer demand for summer 2009 (*Id.* at 6).

1. Water Facilities Hook-Up Fee

The Company requests that the Commission increase the existing Water Facilities Hook-Up Fees applicable in the Company's Agua Fria Water District, based on the fair-value finding for the Agua Fria District in Decision No. 67093 (June 30, 2004), as follows:

Meter Size	Existing Water Facilities Hook-Up Fee	Proposed Water Facilities Hook-Up Fee
5/8 x 3/4-inch	$ 1,150	$ 3,280
3/4-inch	1,725	4,920
1-inch	2,875	8,200
1 1/2-inch	5,750	16,400
2-inch	9,200	26,240
3-inch	18,400	52,480
4-inch	28,750	82,000
6-inch or larger	57,500	164,000

Arizona-American believes that its proposal to finance the White Tanks Project with hook-up fees, which will be treated as contributions in aid of construction ("CIAC"), is equitable because customer growth is largely driving the need for the plant (Surrebuttal Testimony of Thomas M. Broderick, Exh. A-7 at 7). The Company asserts that the amount of the hook-up fee increase it is requesting is reasonable because it is in line with fees charged by West Valley municipal water providers (*See* Exh. A-2 at 9-10; *See also* Direct Testimony of Mike Brilz, Exh. P-1 at 5 and attached Exhibit).

2. Accounting Requests

a. Post-in-Service Allowance for Funds Used During Construction ("AFUDC")

Arizona-American requests that the Commission authorize the Company to record post-in-service AFUDC on the excess of the construction cost of the White Tanks Project (including development, site acquisition, design, company labor, overheads, and AFUDC) over the amount of directly related hook-up fees collected through December 31, 2015, or the date that rates become effective subsequent to a rate case that includes 80 percent (based on estimated cost) of the White Tanks Project in rate base, whichever comes first. The Company also requests that, in order to avoid depressing the Company's earnings and increasing its revenue requirement, the Company be allowed to defer post in-service depreciation expense in excess of the associated amortization of contributions. Additionally, the Company requests that it be allowed to propose, in its next rate case filing for the Agua Fria Water District, specific accounting entries to meet this objective.

The application states that when the plant is completed, there will still be a significant shortage between capital expenses and hook-up fees (Exh. A-2 at 11). The Company requests the ability to book post-in-service AFUDC in order to keep it whole on its investment until such time that the accumulated hook-up fees are sufficient to fund the entire plant balance. This treatment will not affect customer rates because the additional post-in-service AFUDC will later be completely offset by hook-up fee funds.

b. Rate Base – Excess Contribution Exclusion

Arizona-American requests authorization to exclude from rate base the contribution balance

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of hook-up fees directly related to the White Tanks Project collected subsequent to the effective date of a decision in this case over the aggregate of (1) construction expenditures (including development, site acquisition, design, company labor, overheads, and AFUDC) for the same period that are included in rate base and (2) any costs deemed imprudently incurred from contributions used to calculate rate base until December 31, 2015.

The Company states that because construction work in progress ("CWIP") is not typically included in rate base, the collected hook-up fees should not be considered to be CIAC until a corresponding amount of plant, funded by hook-up fees, enters service (Exh. A-2 at 11). Otherwise, the CIAC balance would grow faster than rate base, causing rate base to decline rapidly as hook-up fees are collected, only to then bounce back as plant enters service (*Id.*).

3. <u>2008 Rate Filing Requirements</u>

a. <u>Revised Hook-Up Fee Proposal</u>

Arizona-American requests that the Commission require Arizona-American, as part of its 2008 Agua Fria rate case filing, to include a proposal to adjust the Water Facilities Hook-Up Fee Tariff, based on information known to that date, including:

1) Actual to-date and remaining plant costs;
2) The effects of any third-party treatment contracts;
3) Actual hook-up fee collections;
4) Revised projected customer additions and meter preferences; and
5) Future Agua Fria Water District capital requirements.

The Company states that this will allow the Commission to reset the hook-up fees as necessary, based on the best information available at the time.

b. <u>Operation and Maintenance ("O&M") Expense Recovery Mechanism</u>

Arizona-American requests that the Commission require Arizona-American, as part of its 2008 Agua Fria rate case filing, to include a proposed mechanism, similar to the Commission's arsenic cost recovery mechanism ("ACRM") procedure, to defer and subsequently recover O&M expense incurred for the White Tanks Project until such expenses can be placed in base rates.

The Company estimates that the O&M costs for the White Tanks Project will be approximately $1.5 million per year, base on current media, electricity, and other costs.

4. MWD Treatment Facility

Arizona-American requests that the Commission find that it would be imprudent for Arizona-American, instead of building its own water treatment facility, to purchase treatment services from MWD at the water treatment facility MWD has proposed in this proceeding. Arizona-American disagrees with MWD's assertion that its plant will cost less than Arizona-American's, and believes that MWD's cost estimate is seriously flawed. In addition, Arizona-American states that the proposed MWD plant site would require Arizona-American to construct additional interconnection facilities, which would increase Arizona-American's costs.

The Company calculates that MWD proposal to build a treatment plant and have Arizona-American purchase treatment capacity would require a large rate increase (an additional $21.07/month) for all of Arizona-American's customers (Surrebuttal Testimony of Thomas Broderick, Exh. A-7 at 6). Arizona-American argues that if it were to purchase capacity from MWD and construct the additional facilities that would be required to make such a purchase possible, the Company would have to file a rate application in order to recover the increased costs (*Id.* at 7-8), and would experience regulatory lag in the cost recovery.

Arizona-American argues that MWD's assertions that building the plant with hook-up fee financing would harm the Company's financial strength are speculative and not supported by the evidence in this proceeding. The Company also disagrees with MWD's opinion that the hook-up fee proposal would violate the fair value requirement of the Arizona Constitution, and points out that the Company is seeking to increase the amount of the current hook-up fee, which was initiated outside a rate case, based on the fair value finding in Decision No. 67093 (June 30, 2004). The Company states that its proposal to finance the White Tanks Project with hook-up fees places the costs on new customers, whose addition to the system is causing the need for the plant. Arizona-American believes this is preferable to placing the costs on both existing and new customers, which it asserts would be the result if Arizona-American were to purchase treatment capacity from an MWD plant (*Id.* at 7).

The Company is also concerned with the possibility that a capacity commitment for a large portion of an MWD plant would require the agreement to be treated as a capital lease, in which case the lease asset would be included in rate base to recover the asset as well as lease costs, further exacerbating the rate burden on customers and the regulatory lag impact on the Company (Co. Br. at 20-21).

Arizona-American further asserts in support of its position that the proposed MWD plant has yet to be designed; MWD's proposed construction schedule is overly optimistic and unreliable due to the conceptual nature of the proposed plant; Arizona-American would not be the operator of MWD plant; MWD's irrigation wells would not provide back-up water drinking water supplies without extensive additional treatment costs; the proposed MWD plant site would eventually require costly expansion of the Beardsley Canal; MWD lacks experience in designing, operating, or constructing potable water treatment facilities; MWD has not acquired customers for its proposed plant; and MWD has no obligation to construct the plant and is not subject to the Commission's jurisdiction (*Id.* at 21-28).

Arizona-American also states that requiring Arizona-American to deal with MWD would put the Company in a disadvantageous bargaining position (*Id.* at 28-29). Arizona-American opposes each item of relief requested by MWD in this proceeding.

B. MWD

MWD states that it has a demonstrated history of providing essential and reliable water and electric services at low cost, and asserts that it will bring its record of service of more than 75 years to its plans to construct a regional water treatment plant for Phoenix's West Valley. MWD asserts that its service area is rapidly changing, that it must adapt in order to continue to fulfill its purpose of serving its landowners, and that part of MWD's response to the changes in its service area is construction of a regional surface water treatment plant. MWD states that it plans to utilize the plant to treat its own Agua Fria surface water, which must be used for the benefit of the landowners of MWD.

MWD's witness testified that MWD will build the plant regardless of other customers it may serve (Surrebuttal Testimony of James R. Sweeney, Exh. D-46 at 3). MWD states that it would provide treatment services to Arizona-American for the Company's CAP allocation if it reaches an agreement with Arizona-American. MWD has not finalized any service contracts, but its witness testified that MWD is in "an advanced state of discussions" with the City of Goodyear, which has given a verbal commitment to the project, subject to working out a satisfactory contract, to treat that city's CAP allocation (Direct Testimony of James R. Sweeney, Exh. D-45 at 5). MWD states that it will contract with other water providers in the area who desire treatment services (*Id.*).

MWD states that Arizona-American has not provided it with a firm price for treatment of MWD's surface water (MWD Reply Br. at 8), but argues that its planned plant will cost less than the plant proposed by Arizona-American (MWD Br. at 9-11). MWD asserts that its plant will have lower construction costs, lower operating costs, and lower financing costs than Arizona-American. MWD also states that it would provide a "landowner credit" to reduce customers' bills (*Id.* at 9). MWD argues on brief that its proposed larger plant site will allow a larger buffer area than Arizona-American's proposed site (*Id.* at 12-13).

MWD disagrees with Arizona-American regarding the rate impact on Arizona-American's customers if Arizona-American were to purchase capacity from an MWD regional plant as opposed to going forward with its own plans for constructing the White Tanks Project. MWD disputes the assumptions in Arizona-American's analysis regarding MWD recovery of its capital costs (*See* Tr. at 217-218: Tr. at 485); regarding the date MWD plant would come on line (*See* Tr. at 218-219; Surrebuttal Testimony of James P. Albu, Exh. D-44 at 7); regarding the amount of land costs that MWD would recover in its charges for treatment services (*See* Tr. at 219; Tr. at 577-78, 221-222, Exh. D-7); and regarding the additional cost to Arizona-American related to use of MWD's plant instead of Arizona-American's White Tanks Project (*See* Tr. at 222-223; Exh. D-44 at 8; Tr. at 142; Exh D-4; Tr. at 125-128). MWD asserts that access to its Agua Fria surface water will be available only at MWD plant (*See* Tr. at 55), and therefore, Arizona-American will be required to build facilities to access MWD's Agua Fria that surface water in any event. In its reply brief, MWD posits that if Arizona-American purchases Agua Fria surface water from MWD, the parties can work together to minimize use of the 60 groundwater wells owned by MWD, but that "[t]he opportunity will be lost if Arizona-American goes it alone and builds a separate plant" (MWD Reply Br. at 9).

MWD argues that Arizona-American's plan to construct the plant will lower the Company's equity ratio, and will result in high levels of contributed plant (MWD Opening Br. at 14-15). Based on its view that no hook-up fees are necessary, MWD asserts that it would not be just and reasonable to require increased hook-up fees. MWD also argues that the proposed hook-up fee proposal is not revenue neutral, that the hook-up fees are "rates" and that the Commission cannot adopt Arizona-American's proposed hook-up fee without a fair value finding. MWD does not seem opposed to the concept of a hook-up fee; however, as it suggests that the Commission could approve a hook-up fee to cover the extra cost Arizona-American claims it would incur to purchase treatment capacity from MWD instead of building its own plant (MWD Reply Br. at 11).

In its closing brief, MWD alleges that Arizona-American is violating its existing hook-up fee tariff when it requires developers to contribute wells or collect advances for offsite projects (*Id.* at 19). MWD is also opposed to Arizona-American's requested accounting orders on the grounds that they are "unprecedented" (*Id.*).

MWD requests that the Commission grant it the following relief:

1) Deny Arizona-American's request to increase its hook-up fee;

2) Deny Arizona-American's request for an accounting order to accrue AFUDC;

3) Deny Arizona-American's request for an accounting order to delay recognition of CIAC until related plant is in service;

4) Deny Arizona-American's request that it be ordered to include a proposal for an O&M Expense Adjustor in its next rate case for its Agua Fria division;

5) Authorize Arizona-American to reflect the margin credit proposed by MWD on the bills for Arizona-American's Agua Fria Division;

6) Direct Arizona-American to cooperate in developing and administering the margin credit program;

7) Order Arizona-American to account for all advances and contributions it has received for off-site facilities beyond those collected through its off-site hook-up fee after that tariff went into effect;

8) Order Arizona-American to refund all advances and contributions it has received for off-site facilities beyond those collected through its off-site hook-up fee after that tariff went into effect; and

9) If the Commission grants any of Arizona-American's requests, then in the alternative, MWD requests that, in order to protect Arizona-American's customers, the Commission order the following:

A) Any hook-up fees collected by Arizona-American should be subject to refund, should the Commission determine in a rate case that lower fees are appropriate, or should the courts find the fee increase to be invalid;

B) To guarantee Arizona-American's ability to make the refund, it should be ordered to post a bond in the amount of the estimated hook-up fee collections for the next five years;

C) The Commission should make clear that O&M costs for Arizona-American's plant will be evaluated under the Commission's traditional ratemaking methods;

D) The Commission should rule that no portion of the cost of Arizona-American's plant will be allowed in rate base; and

E) The Commission should rule that it will not allow an increased cost of capital due to financial weakness caused by Arizona-American building the plant.

C. DEVELOPERS

1. <u>Stipulation Regarding Paid Hook-Up Fees</u>

Courtland, Taylor Woodrow, CHI, Trend, and Arizona-American stipulated that Arizona-American will not impose or seek to impose higher hook-up fees on the following developer projects, for which Arizona-American has entered into Water Facilities Line Extension Agreements ("LXAs") which are at operational acceptance for purposes of the LXAs, and for which the developers have already paid hook-up fees under Arizona-American's existing hook-up fee tariff: Greer Ranch North (Courtland), Sycamore Farms (Taylor Woodrow), Sarah Ann Ranch (CHI), and Cortessa (Trend). The parties further stipulate that any future true-ups to hook-up fees already paid for those developer projects will be based on the Commission-approved tariff that existed at the time the original payment was made. The above-described stipulation was admitted to the record in this proceeding as Hearing Exhibit A-1 ("Stipulation").

CHI, Courtland, and Taylor Woodrow disagree with the statement in MWD's closing brief that adoption of the Stipulation "will result in hook-up fees not being collected from many properties

- the same properties that will be the first to develop." CHI, Courtland, and Taylor Woodrow assert that MWD's statement is inaccurate, and that the Stipulation will not result in Arizona-American foregoing revenue to which it otherwise would have been entitled.

Trend also disagrees, stating that the result of the Stipulation would not be to waive collection of hook-up fees, as claimed by MWD, but that it simply provides clarification for developers who have already paid 100 percent of the required hook-up fees.

We find the terms of the Stipulation entered by with CHI, Courtland, Taylor Woodrow, Trend, and the Company to be reasonable, because they provide clarification for the Company and for developers who have already paid 100 percent of the required hook-up fees.

2. CHI, Courtland, and Taylor Woodrow

CHI, Courtland, and Taylor Woodrow are all currently developing projects in Arizona-American's Agua Fria District, and have each entered into LXAs with Arizona-American for the provision of water utility service to their projects. CHI, Courtland, and Taylor Woodrow agree that there is an immediate need and necessity for the proposed surface water treatment plant, but take no position on whether Arizona-American or MWD should construct the plant or operate the plant.

CHI, Courtland, and Taylor Woodrow request that the Commission's Decision in this matter reflect that Arizona-American may not charge them new hook-up fees to the extent that they have already paid hook-up fees based upon Arizona-American's existing tariff pursuant to the terms of their respective LXAs or other agreements.

CHI, Courtland, and Taylor Woodrow also request that the Commission address, in this Decision, three additional issues related to water supply for developers. They request that the Commission preclude Arizona-American from instituting a new service moratorium and require Arizona-American to set meters in circumstances where the developer has supplied the required water to serve the increased demand of a new project.

CHI, Courtland, and Taylor Woodrow also request that the Commission order Arizona-American to use its best efforts to work with MWD to obtain both short-term and permanent water supplies to negate (where possible) the requirement that additional wells must be drilled during construction of the surface water treatment plant and thereafter.

Lastly, CHI, Courtland, and Taylor Woodrow request that the Commission order Arizona-American to review its existing LXAs and other agreements in the Agua Fria District which require developers to drill new wells in order to determine whether the agreements should be amended to reduce the number of required wells.

It is reasonable to require the Company to address the three issues related to water supply raised by CHI, Courtland, and Taylor Woodrow set forth above.

3. <u>Trend</u>

Trend is currently in the process of building homes on lots located in Arizona-American's Agua Fria District, and has paid hook-up fees in association with its development project. Trend requests that the Commission confirm the terms of the Stipulation. As stated above, we find the terms of the Stipulation reasonable.

4. <u>Fulton, Suburban and Westcor/Surprise</u>

Fulton is currently developing a portion of a master-planned community known as Prasada, located in Arizona-American's Agua Fria District. Suburban and Westcor/Surprise are developing a mix of retail centers, a regional shopping center, an auto mall, office complexes, medical facilities, neighborhood grocery and service retail centers, and some medium- to high-density residential components located in Arizona-American's Agua Fria District. Fulton, Suburban and Westcor/Surprise agree that there is an immediate need and necessity for the proposed surface water treatment plant, but take no position on whether Arizona-American or MWD should construct the plant or operate the plant.

Fulton, Suburban and Westcor/Surprise take the position that regardless of when the plant becomes operational, Arizona-American should be precluded from instituting a new service hook-up moratorium on any project where the developer provides the "wet" water supply for the particular project pursuant to an LXA between Arizona-American and a developer. They make the same request as CHI, Courtland, and Taylor Woodrow that the Commission's Decision in this proceeding preclude Arizona-American from instituting a new service moratorium in such circumstances, and that the Decision order Arizona-American to continue to set meters at any development that has provided the required water supply for such development pursuant to the terms of the LXA or other agreement between Arizona-American and the developer.

Fulton, Suburban and Westcor/Surprise join CHI, Courtland, and Taylor Woodrow in their request that the Commission order Arizona-American to use its best efforts to work with MWD to obtain both short-term and permanent water supplies to negate (where possible) the requirement that additional wells must be drilled during construction of the surface water treatment plant and thereafter.

Fulton, Suburban and Westcor/Surprise also join CHI, Courtland, and Taylor Woodrow in their request that the Commission order Arizona-American to review its existing LXAs and other agreements in the Agua Fria District which require developers to drill new wells in other to determine if the agreements should be amended to reduce the number of required wells.

Fulton, Suburban and Westcor/Surprise further request that Arizona-American be ordered to review, in conjunction with its review of existing LXAs and before Arizona-American requires developers to drill new wells, less costly alternatives for the utility to supply water for new developments to minimize and otherwise supplant the number of new wells that will need to be drilled in the Agua Fria District, with such review to include the proposed 3.5 mile contingency pipeline alternative in relation to the requirement for new wells to be drilled in the southern portion of the Agua Fria District.

The witness for Suburban and Westcor/Surprise testified that in order to meet the current requirements of Arizona-American and MWD, it must drill nine new potable wells in an area where there is poor water quality and capacity (Surrebuttal Testimony of Scott Wagner at 4). Suburban and Westcor/Surprise believe this is attributable to the lack of coordinated effort in the region. Fulton, Suburban and Westcor/Surprise request that the Commission order Arizona-American to coordinate with all interested parties in a regional planning process to assist the Commission in addressing groundwater issues in conjunction with construction of the surface water treatment plant.

The additional requests made by Fulton, Suburban and Westcor/Surprise in regard to water supply issues are reasonable, and we will require the Company to address the two additional issues set forth above.

5. <u>Pulte</u>

Pulte is developing or building homes in several locations in Arizona-American's Agua Fria Water District. Pulte states that it supports the expedited construction of a surface water treatment facility in the West Valley. Pulte takes the position that if the hook-up fee request is granted, the amount should not exceed Staff's proposed graduated fees starting at $3,280 for a 5/8 x 3/4 - inch meter.

Pulte also requested, on brief, that the Commission require Arizona-American to insert new language in its tariff to indicate that the hook-up fee changes effective in 2007 will not be charged retroactively, and requiring that hook-up fees be offset by the cost of the off-site facilities (non-distribution facilities) contributed to Arizona-American. Arizona-American responds that the issue of offsetting hook-up fees by the cost of off-site facilities is presently resolved on a case-by-case basis in each developer's LXA. The Company states that the LXA specifies the amount of hook-up fee credit to be applied, if any, and that the LXA is then submitted to the Commission for approval. Arizona-American does not believe that a blanket requirement of a hook-up fee offset is appropriate. The Company argues that alteration of the Company's administration of its hook-up fee offsets is not appropriate in this case, because the issue was not noticed in this proceeding and no evidence has been submitted on the issue.

We agree with Arizona-American that there was not sufficient evidence presented on this issue to inform a determination on whether Pulte's request for mandatory hook-up fee offsets should be granted. We note that processes currently exist to aid parties in coming to a resolution of issues in dispute between Pulte and the Company. If parties to an LXA are unable to come to an agreement on LXA issues, the parties may avail themselves of the Commission's informal dispute resolution processes, or may resort to the filing of a formal complaint, if necessary.

D. RUCO

RUCO supports Commission approval of Arizona-American's hook-up fee proposal outlined in the Revised Application to finance the cost of the White Tanks Project. RUCO believes the proposal is in the ratepayers' best interests and is fair to the Company. In support of its position, RUCO states that the Company needs to serve its customers; construction of a treatment plant is necessary to meet the Company's service requirements; the Company is unable to finance the plant at this time; and financing the plant through hook-up fees, which will be treated CIAC, is a cost-free source of financing, which has the effect of lowering customer rates because CIAC is not placed in rate base.

Of the two hook-up fee options proposed by the Company, RUCO prefers the second option, which would start at $4,700 for a 5/8 by 3/4-inch meter, because it would result in smaller accruals of AFUDC, which temporarily flows into customers' rates. RUCO does not object to Arizona-American's proposal to seek, in its upcoming 2008 rate case filing, adjustments to the hook-up fees and a mechanism for recovery of O&M costs, but requests that if the Commission approves this proposal, that the Decision indicate that the Commission is not predetermining the appropriateness of any such hook-up fee modifications or O&M cost recovery mechanism.

RUCO states that it has no objection to the issuance of an accounting order as requested by the Company, and that it does not object to the Company seeking adjustments to the hook-up fees and a mechanism to recover O&M costs for the White Tanks Project in its 2008 rate case.

RUCO opposes MWD's request to deny the Company's hook-up fee proposal, arguing that the Company, not MWD, is responsible for building the plant necessary to serve its customers. RUCO states that in the event the Commission grants the Company's hook-up fee requests, RUCO does not object to conditions 9(A) and (B) as proposed by MWD. RUCO objects to the remaining conditions proposed by MWD (9(C-E)) on approval of a hook-up fee, based on RUCO's belief that the Commission should not determine the issues raised by those proposed conditions outside of a rate case.

RUCO asserts that MWD's request that the Commission compare the Company's and MWD's cost estimates should be rejected as unreasonable and contrary to ratemaking principles. RUCO states that MWD's request constitutes a request for a prudence determination. RUCO argues that the Commission need not, and should not, determine the prudence of the Company's decision to build the White Tanks Project in this proceeding. RUCO argues that while evidence was presented in this proceeding regarding estimated costs, and regarding the parties' respective motivations for building the plant, it is the Company, and not MWD, which is responsible for serving the Company's customers. RUCO is concerned that MWD, as an entity not regulated by the Commission, is not subject to the Commission's oversight, either for the rates it will charge or for future disposal of the plant. RUCO points out that if Arizona-American were to purchase capacity from a plant built by MWD instead of building the plant itself, MWD would have greater bargaining power than the Company, because it would be the sole source of treatment capacity for the area. RUCO states that this situation could lead to unnecessarily high rates for Arizona-American's customers.

E. STAFF

Staff believes that the Commission needs to decide only a single issue in this matter: whether to grant Arizona-American's application to fund construction of a surface water treatment facility through an increase in hook-up fees for the Company's Agua Fria Water District. The Agua Fria Water District is located in an Active Management Area ("AMA"), which makes use of surface water to serve this territory an attractive option for the Company, provided the treatment can be accomplished economically. Staff evaluated the Company's application and determined that Arizona-American's proposal for constructing and financing the plant is a viable proposal. Staff is recommending approval of the Company's requested relief.

Staff therefore believes it is unnecessary for the Commission to consider the evidence and analysis presented by MWD regarding its estimates of which entity can more economically build a water treatment facility because MWD is not regulated by the Commission. Staff argues that not only is such consideration of the economic comparison unnecessary, but that it would be inappropriate. Staff points out that the current dispute has come about due to non-cooperation between two competing utility interests, one of which is not regulated. Staff argues that under these circumstances, a Commission determination on the basis of waste to the general public finances would be a very difficult standard to enforce in a regulatory scheme based upon regulated monopolies.

Staff argues that a comparison of MWD's proposal with the Company's plan is therefore largely irrelevant. Staff further argues, however, that even if the Commission were to consider such a comparison, Arizona-American's plan is superior, both in design and from a financial standpoint. Staff points out that as of the date of the hearing, MWD's proposal lacked specific detail, even as to its proposed size, and that plans for MWD's proposed plant were not available in any firm form. In contrast, Arizona-American's proposal for a 13.5 MGD plant, consisting of three trains at 6.67 MGD each, has already been designed, competitively bid, and awarded to the lowest bidder. Staff argues that because MWD's proposal lacks specifics and has not been finalized, financial comparison is also difficult. Regarding financing costs, Staff states that the range of interest rates from 3 1/2 to 5 percent that MWD claims are available to it would in any event be more expensive than the Company's proposed hook-up fee financing, which is regarded as zero cost capital (*See* Tr. at 647-648). In further support of its position, Staff points to the inability of MWD's financial witness to ascertain that the figures he was given to use as inputs to calculate the rates MWD would charge for water treatment are the actual figures MWD would use in its business dealings with the water companies or with its customers (*See* Tr. at 368-369).

Staff is recommending approval of the Company's requested relief, based on its evaluation of the Company's application and Staff's determination that Arizona-American's proposal for constructing and financing the plant is a viable proposal. Staff does not believe that it would be appropriate for the Commission to make a determination regarding whether Arizona-American or MWD should build the regional plant. However, Staff recommends that in the event the Commission were to follow MWD's suggestion to compare cost estimates and somehow "allow" only one plant to be built, Arizona-American's application should also be approved, based on Staff's evaluation that the evidence supports the plant being built by Arizona-American.

III. <u>ANALYSIS</u>

No party disputes that MWD is, as it describes itself, "a critical link in the water supply of the west valley region," or that MWD has provided excellent and low cost service for many years. The Commission respects MWD's record of service to its landowners and its continued commitment to its landowners through its ownership of the Beardsley Canal, creation of Lake Pleasant, and ownership of Agua Fria surface water rights.

In the context of this case, however, MWD's speculations regarding the costs of the two "competing" plans for surface water treatment plants are not helpful to our determination whether it serves the public interest to approve Arizona-American's financing proposal. As RUCO states in its reply brief, Arizona-American is not requesting authority to build the plant. The request before us is a narrow one. Arizona-American seeks a grant of authority to institute a method of financing the construction of the White Tanks Project. In no small part due to MWD's participation in this proceeding, we have before us a record that clearly demonstrates the reasonableness and viability of Arizona-American's proposal for constructing and financing the White Tanks Project.

No party to this proceeding disagrees with MWD that it has a long history of low utility rates, a public purpose of serving the landowners of MWD, and a democratic structure. MWD argues that these factors demonstrate that MWD would not charge Arizona-American rates for treatment services higher than Arizona-American's cost of service. However, we must take into consideration the facts that MWD's purpose and duty is to serve not Arizona-American's ratepayers, but its landowners, and that MWD is governed by an elected board not subject to the Commission's jurisdiction. In contrast to MWD's duty to its landowners and self-governance structure, Arizona-American is a public service corporation with a legal duty to provide adequate service to its customers at reasonable rates, while subject to the Commission's ratemaking and regulatory authority. MWD is not subject to the same legal obligations regarding rates as Arizona-American. In addition, there is no contractual agreement in place to assure either the Company or the Commission of a firm price that MWD would charge for treatment services. We acknowledge MWD's argument that Arizona-American likewise has not provided MWD a firm treatment price. However, the ramifications of the lack of a firm price differ for a non-regulated versus a regulated entity. While the Commission has ongoing oversight over Arizona-American's facilities and services, if MWD's service rates were to increase in the future, neither the Commission nor Arizona-American's ratepayers would have a means of insuring the reasonableness of the rates.

MWD's assertions and arguments do not provide a basis for denial of Arizona-American's request or for the grant of any of the relief requested by MWD, with the exception of MWD's recommendation that hook-up fees should be subject to refund, should the Commission determine that a refund is appropriate. Similarly, Arizona-American's arguments and assertions do not provide a basis for a finding that it would be imprudent for Arizona-American to purchase treatment services from MWD. Ultimately, it is Arizona American's business decision whether to build its own facility or purchase treatment services from MWD. As with all business decisions of regulated utilities, the prudence of the Company's decision will be subject to examination, if necessary, in a future rate proceeding.

IV. CONCLUSION

Arizona-American is a public service corporation. As a regulated utility, it has an obligation to provide water utility service to its customers at reasonable rates. The Company has demonstrated a need to build the proposed plant and has presented a sound plan by which to finance its construction.

We find that it is in the public interest to approve Arizona-American's requests for approval of an increase to its existing Water Facilities Hook-Up Fee, for accounting orders, and for 2008 rate case filing requirements. The record evidence in this proceeding supports approval. We need not, and do not, make a determination here regarding the superiority of one party's plan for a surface water treatment plant over another, or regarding the Company's prudence in exercising its chosen option.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. Arizona-American is a public service corporation engaged in providing water and wastewater utility services to the public in portions of Maricopa, Mohave, and Santa Cruz Counties, Arizona, pursuant to various Certificates of Convenience and Necessity ("CC&Ns") granted to Arizona-American and its predecessors in interest. The Company presently provides utility service to approximately 100,000 water customers and 50,000 sewer customers in Arizona.

2. Arizona-American's Agua Fria District is located in the developing western Phoenix metropolitan area between the White Tank Mountains and the 101 Expressway, mostly to the north of Interstate 10.

3. On October 11, 2005, Arizona-American filed the above-captioned application with the Commission.

4. By Procedural Order issued December 19, 2005, a procedural schedule was set for the

processing of the application, which included a hearing on the application, public notice requirements, and intervention deadlines.

5. Intervention was granted to RUCO by Procedural Order issued January 10, 2006.

6. On January 23, 2006, the Company filed a Confirmation of Mailing and Affidavit of Publication indicating that public notice of the hearing was accomplished in accordance with the requirements set forth in the December 19, 2005, Procedural Order.

7. On February 10, 2006, RUCO filed Direct Testimony of its witness on the October, 2005 application.

8. Also on February 10, 2006, Staff filed a Staff Report on the October, 2005 application.

9. On March 2, 2006, a Pre-Hearing Conference convened at the time set by the December 19, 2005, Procedural Order.

10. By Procedural Order issued March 2, 2006, the Company's request that the procedural schedule in this matter be suspended, due to issues that had arisen between the Company and MWD, was granted.

11. On September 1, 2006, after the filing of several status reports, and following a Procedural Conference held on August 1, 2006, the Company filed a Revised Application in this docket.

12. On September 14, 2006, a Telephonic Procedural Conference was held for the purpose of discussing the appropriate process for a Commission determination in this docket. The Company, RUCO and Staff attended. The parties agreed to confer and either jointly file a proposed procedural schedule, or file separate proposals in the event no agreement was reached.

13. On September 25, 2006, Staff filed a Joint Request for a Procedural Order on behalf of Staff, RUCO, and the Company. The Joint Request stated that the parties did not believe, at that time, that an evidentiary hearing was necessary. The Joint Request proposed that Staff file a Staff Report and Staff Recommended Order by October 27, 2006; that the Company and RUCO file responses to the filing by November 6, 2006; and that if there were disputed issues, that a Recommended Opinion and Order be prepared by the Hearing Division.

14. On October 5, 2006, a Procedural Order was issued generally adopting the parties'

recommendations, and stating that the Hearing Division or the Commission might determine that additional information or a hearing may be required in this matter prior to a Commission Decision.

15. On October 27, 2006, Staff filed a Staff Report and Staff Recommended Order, recommending approval of the Company's proposed hook-up fee and accounting order as requested in the Revised Application.

16. Between October 23, 2006 and December 6, 2006, Applications to Intervene in this proceeding were filed by Pulte, CHI, Courtland, Taylor Woodrow, Trend, Fulton, Suburban and Westcor/Surprise. These parties were all granted intervention.

17. On November 8, 2006, MWD filed an Application for Leave to Intervene.

18. On November 29, 2006, the Company filed a Request for Expedited Hearing. In that filing, the Company withdrew its prior opposition to MWD's Application for Leave to Intervene. The Company's Request included a list of issues for hearing and a proposed hearing schedule.

19. Intervention was granted to the Developers and MWD.

20. On December 13, 2006, a Procedural Order was issued setting a Prehearing Conference for December 21, 2006.

21. A Pre-Hearing Conference was held as scheduled on December 21, 2006. Arizona-American, MWD, CHI, Courtland, Taylor/Woodrow, Fulton, RUCO and Staff appeared through counsel and discussed several procedural matters relating to the hearing. The parties also addressed the possibility of settling some disputed issues, and were informed of the necessity of providing notice and an opportunity for participation of all parties in any settlement discussions that might be held.

22. On December 21, 2006, a Procedural Order was issued setting a hearing for March 19, 2007, and setting associated procedural deadlines.

23. On January 11, 2007, the Company filed an Affidavit of Publication verifying that notice of this proceeding was published in accord with the requirements of the December 21, 2006 Procedural Order.

24. Between January 22, 2007 and March 12, 2007, the parties prefiled Direct, Rebuttal, and Surrebuttal testimonies.

25. On March 14, 2007, Arizona-American filed an Objection to Data Requests.

26. On March 14, 2007, MWD filed a Motion to Strike and Alternative Motion for Expedited Discovery.

27. On March 15, 2007, Arizona-American filed its Response to Motion to Strike.

28. The hearing in this matter convened as scheduled on March 19, 2007, before an authorized Administrative Law Judge of the Commission, and concluded on March 26, 2007. At the hearing, MWD withdrew its Motion to Strike based on the Company's agreement to provide data responses to MWD. The parties appeared through counsel, presented testimony, and cross-examined witnesses.

29. On March 28, 2007, MWD filed Late-Filed Exhibits D-52 and D-53.

30. Arizona-American, Pulte, Trend, CHI, Courtland, Taylor/Woodrow, Fulton, Suburban, Westcor, MWD, RUCO, and Staff filed closing briefs.

31. On April 27, 2007, reply briefs were filed by Arizona-American, CHI, Courtland, Taylor/Woodrow, Trend, MWD, and RUCO.

32. On April 30, 2007, Arizona-American filed a Supplement to Reply Brief.

33. Arizona-American requests authorization to record post-in-service AFUDC on the excess of the construction cost of the White Tanks Project (including development, site acquisition, design, company labor, overheads, and AFUDC) over the amount of directly related hook-up fees collected through December 31, 2015, or the date that rates become effective subsequent to a rate case that includes 80 percent (based on estimated cost) of the White Tanks Project in rate base, whichever comes first. The Company also requests that, in order to avoid depressing the Company's earnings and increasing its revenue requirement, the Company be allowed to defer post in-service depreciation expense in excess of the associated amortization of contributions. Additionally, the Company requests that it be allowed to propose, in its next rate case filing for the Agua Fria Water District, specific accounting entries to meet this objective.

34. Arizona-American requests authorization to exclude from rate base the contribution balance of hook-up fees directly related to the White Tanks Project collected subsequent to the effective date of a decision in this case over the aggregate of (1) construction expenditures (including

development, site acquisition, design, company labor, overheads, and AFUDC) for the same period that are included in rate base and (2) any costs deemed imprudently incurred from contributions used to calculate rate base until December 31, 2015. The Company's wording "contribution balance of hook-up fees directly related to the White Tanks Project" seems to presume that there may be, at some future date, a balance of hook-up fees that is directly related to the White Tanks Project, but that is not part of the "contribution balance." While the Company may propose, at some future date, some mechanism which may result in such a balance of hook-up fees, there is no such proposal pending, and no Commission determination on such a proposal. Our approval of the Company's request for an accounting order herein should not be viewed as a pre-determination of any future request.

35. Arizona-American requests that the Commission require Arizona-American, as part of its 2008 Agua Fria rate case filing, to include a proposal to adjust the Water Facilities Hook-Up Fee Tariff, based on information known to that date, including:

1) Actual to-date and remaining plant costs;
2) The effects of any third-party treatment contracts;
3) Actual hook-up fee collections;
4) Revised projected customer additions and meter preferences; and
5) Future Agua Fria Water District capital requirements.

36. Arizona-American requests that the Commission require Arizona-American, as part of its 2008 Agua Fria rate case filing, to include a proposed mechanism, similar to the Commission's ACRM procedure, to defer and subsequently recover O&M expense incurred for the White Tanks Project until such expenses can be placed in base rates.

37. It is in the public interest to approve Arizona-American's requests for accounting orders.

38. It is in the public interest to authorize, but not require, Arizona-American to make the 2008 rate case filings it requests.

39. Several of the Developers have paid hook-up fees to Arizona-American under Arizona-American's existing Water Facilities Hook-Up Fee Tariff for development projects.

40. It is reasonable to require Arizona-American to charge developers for hook-up fees in accordance with the tariffs in effect at the time payment of such fees is required pursuant to the terms of the applicable LXA.

41. It is reasonable to require that any true-up of hook-up fees which were paid prior to the effective date of the new Water Facilities Hook-Up Fee Tariff approved by this Decision be based on the hook-up fee tariff in effect at the time the hook-up fee payment was made.

42. There is a need for a coordinated potable groundwater procurement program in the Agua Fria District. Accordingly, in order to preserve groundwater resources, as well as to negate the necessity and expense of having additional and possibly redundant wells drilled in the Agua Fria District, it is reasonable to require Arizona-American, as the certificated water service provider in the area, to coordinate with all interested parties in a regional planning process to address groundwater issues in conjunction with the construction of a surface water treatment plant.

43. It is reasonable to require Arizona-American to address the water supply issues raised by the Developers, in the manner set forth in the Ordering Paragraphs below.

44. The Company requests, and Staff recommends approval of, the following Water Facilities Hook-Up Fee Tariff:

Meter Size	
5/8 x 3/4-inch	$ 3,280
3/4-inch	4,920
1-inch	8,200
1 1/2-inch	16,400
2-inch	26,240
3-inch	52,480
4-inch	82,000
6-inch or larger	164,000

45. RUCO recommends approval of a Water Facilities Hook-Up Fee Tariff which would collect higher fees, beginning with $4,700 for a 5/8 by 3/4-inch meter, because higher fees would result in smaller AFUDC accruals.

46. We find the Water Facilities Hook-Up Fee Tariff recommended by the Company and Staff to be reasonable, and will adopt it.

47. It is in the public interest to approve Arizona-American's request for authorization to implement the Water Facilities Hook-Up Fee Tariff as discussed herein as a means of financing the

White Tanks Project.

48. A hook-up fee tariff has already been approved for the Agua Fria District in Decision No. 66512 (November 10, 2003). The funds received from the proposed hook-up fees will be separately recorded as CIAC, and therefore Arizona-American will not be entitled to earn a return on the hook-up fees. As such, the hook-up fee funds are revenue neutral and will not increase or decrease the Company's revenues or expenses. Hook-up fees accounted for as CIAC are analogous to funds received from main extension agreements with developers that are treated as advances in aid of construction ("AIAC"). Since no fair value determination is made with respect to AIAC funds, a fair value finding is not required for hook-up fees booked as CIAC.

49. MWD makes a claim that Arizona-American is violating its current hook-up fee tariff. MWD's claim was raised for the first time on brief, and is therefore not properly addressed in this proceeding, which was not noticed as a complaint.

50. The record in this proceeding does not support denial of Arizona-American's requested relief as proposed by MWD.

51. It is appropriate, reasonable, and in the public interest to require that hook-up fees collected under the Water Facilities Hook-Up Fee Tariff approved herein should be subject to refund, should the Commission determine in a future proceeding that a refund is appropriate.

52. The record in this proceeding does not support the grant of any other relief requested by MWD.

53. The record in this proceeding does not support the request by Pulte to require Arizona-American to institute a blanket policy of offsetting hook-up fees by the cost of contributed off-site facilities. Pulte is not precluded from raising this issue in either an informal or a formal dispute resolution process available at the Commission.

CONCLUSIONS OF LAW

1. Arizona-American is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-281, 40-282, 40-301 and 302.

2. The Commission has jurisdiction over Arizona-American and the subject matter of the application.

3. Notice of the application was given in accordance with the law.

4. Under the circumstances of this case, and pursuant to Article XV, §§ 3 and 14 of the Arizona Constitution, Arizona-American's proposed Water Facilities Hook-Up Fees, which will be booked as contributions in aid of construction, do not constitute rates that require a fair value determination prior to approval.

5. Under the circumstances of this case, and pursuant to Article XV §§ 3 and 14 of the Arizona Constitution, it is just, reasonable, and serves the public interest to approve the new Water Facilities Hook-Up Fee Tariff as a means of financing the proposed White Tanks Project in accord with the discussion herein.

ORDER

IT IS THEREFORE ORDERED that the application of Arizona-American Water Company for authority to implement a Water Facilities Hook-Up Fee Tariff in accord with the discussion herein as a means of financing the White Tanks Project shall be, and hereby is, approved.

IT IS FURTHER ORDERED that funds collected pursuant to the Water Facilities Hook-Up Fee Tariff approved herein are subject to refund in the event that the Commission determines in a future proceeding that a refund is appropriate.

IT IS FURTHER ORDERED that with the exception of the preceding Ordering Paragraph, which partially grants relief requested by the Maricopa County Municipal Water District Number One, the relief requested by the Maricopa County Municipal Water District Number One shall be, and hereby is, denied.

IT IS FURTHER ORDERED that this Decision does not predetermine the appropriateness of any modifications proposed in the future to the Water Facilities Hook-Up Fee Tariff approved herein.

IT IS FURTHER ORDERED that Arizona-American Water Company's request for authorization to record post-in-service allowance for funds used during construction on the excess of the construction cost of the White Tanks Project (including development, site acquisition, design, company labor, overheads, and allowance for funds used during construction) over directly related hook-up fees collected through December 31, 2015, or the date that rates become effective subsequent to a rate case that includes 80 percent (based on estimated cost) of the White Tanks

Project in rate base, whichever comes first, shall be, and hereby is, approved.

IT IS FURTHER ORDERED that Arizona-American Water Company's request for authority to defer post in-service depreciation expense in excess of the associated amortization of contributions approved in the previous Ordering Paragraph, and to propose, as part of its 2008 Agua Fria Water District rate case filing, specific accounting entries to meet this objective, shall be, and is hereby, approved.

IT IS FURTHER ORDERED that Arizona-American Water Company's request for authorization to exclude from rate base the contribution balance of hook-up fees directly related to the White Tanks Project collected subsequent to the effective date of this Decision over the aggregate of (1) construction expenditures (including development, site acquisition, design, company labor, overheads, and allowance for funds used during construction) for the same period that are included in rate base and (2) any costs deemed imprudently incurred from contributions used to calculate rate base until December 31, 2015, shall be, and hereby is, approved.

IT IS FURTHER ORDERED that Arizona-American Water Company is hereby authorized to file, as part of its 2008 Agua Fria Water District rate case filing, a proposal to adjust the Water Facilities Hook-Up Fee Tariff approved herein. If such a proposal is filed, it shall include information necessary to allow the Commission to adjust the Water Facilities Hook-Up Fee Tariff as necessary, based on the best information available at the time, including, but not limited to, the following:

1) Actual to-date and remaining plant costs;
2) The effects of any third-party treatment contracts;
3) Actual hook-up fee collections;
4) Revised projected customer additions and meter preferences; and
5) Future Agua Fria Water District capital requirements.

IT IS FURTHER ORDERED that Arizona-American is hereby authorized to file, as part of its 2008 Agua Fria Water District rate case filing, a proposed mechanism to defer and subsequently recover Operations and Maintenance Expense incurred for the White Tanks Project until such expenses can be placed in base rates.

IT IS FURTHER ORDERED that this Decision does not predetermine the necessity for or the appropriateness of any mechanism proposed in the future by Arizona-American Water Company for recovery of Operations and Maintenance Expense incurred for the White Tanks Project.

IT IS FURTHER ORDERED that the request by Pulte Homes Corporation to require Arizona-American Water Company to institute a blanket policy of offsetting hook-up fees by the cost of contributed off-site facilities shall be, and hereby is, denied.

IT IS FURTHER ORDERED that Arizona-American Water Company shall charge developers for hook-up fees in accordance with the tariffs in effect at the time payment of such fees is required pursuant to the terms of the applicable line extension agreement.

IT IS FURTHER ORDERED that any true-up of hook-up fees which were paid prior to the effective date of the new Water Facilities Hook-Up Fee Tariff approved by this Decision shall be based on the hook-up fee tariff in effect at the time the hook-up fee payment was made.

IT IS FURTHER ORDERED that Arizona-American Water Company shall be, and hereby is, precluded from instituting a new service moratorium on the initial hook-ups in circumstances where the developer has supplied the required water to serve the increased demand of a new project pursuant to a line extension agreement.

IT IS FURTHER ORDERED that Arizona-American Water Company shall review its existing line extension agreements in the Agua Fria Water District that require developers to drill new wells, in order to determine whether it is feasible to amend those line extension agreements to reduce the number of required wells, in cooperation with the parties to those line extension agreements.

IT IS FURTHER ORDERED that, in conjunction with the review of line extension agreements required by the previous Ordering Paragraph, Arizona-American Water Company shall consider whether there exist less costly alternatives for the utility and the developers to supply water for new developments in order to minimize and otherwise supplant the number of new wells that will need to be drilled in the Agua Fria District. In the course of this review, Arizona-American Water Company shall consider a proposed 3.5 mile contingency pipeline alternative in relation to the requirement for new wells to be drilled in the southern portion of the Agua Fria District.

IT IS FURTHER ORDERED that Arizona-American Water Company shall use its best efforts to coordinate with all interested parties, including the Maricopa County Municipal Water District Number One, in a regional planning process to obtain both short-term and permanent water supplies to negate, where possible, the need to drill additional wells during construction of a regional surface water treatment plant to serve the Agua Fria Water District.

IT IS FURTHER ORDERED that the Commission shall have complete authority to determine the entitlement and rate making treatment of any proceeds resulting from the sale to third parties of either the White Tanks facility itself, in whole or in part, or of any part of the capacity produced thereby.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, DEAN S. MILLER, Interim Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 27th day of Sept., 2007.

DEAN S. MILLER
INTERIM EXECUTIVE DIRECTOR

DISSENT ______________________

DISSENT ______________________

SERVICE LIST FOR: ARIZONA-AMERICAN WATER COMPANY

DOCKET NO.: W-01303A-05-0718

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DECISION NO. 69914

EXHIBIT
RUCO - 3

UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009

RUCO 11.18 Refer to Mr. Hutchens' rebuttal testimony at page 7, concerning the overall slumping economy.

a. Identify, quantify and explain all steps taken by UNSG in 2008 and 2009 to reduce costs.

b. For each cost reduction effort undertaken by UNSG identified in response to part a, please identify exactly where, and in what amount, each such cost reduction effort has been reflected in UNSG's determination of the Company's requested revenue increase.

RESPONSE: a. See summary of savings realized below:

UNG UNS Gas, Inc

	Jul 07 thru Jun 08	Jul 08 thru Jun 09	Associated reduction:	
A10 Labor Costs	10,929,439	10,889,945	(39,494)	Reduced Overtime, reduced FTEs
158 Supplemental Service	155,874	28,208	(127,665)	Meter reading brought in-house
162 Repairs & Maintenance	263,896	249,701	(14,196)	Reduced vehicle maintenance
A59 Training & Travel	283,462	263,265	(20,197)	Company reduction focus
406 Communications	758,366	535,060	(223,305)	Contract re-negotiation
B64 Transportation	652,670	454,440	(198,230)	Vehicle depreciation reduction

b. These savings are not reflected in the test year. Other increases as reflected within the overall operating cost are still higher than test year and will be in 2009 and 2010. The Company's cost savings efforts have only resulted in mitigating the increases and the effect of regulatory lag.

RESPONDENT: Paul Coleman

WITNESS: David Hutchens

UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009

EXHIBIT
RUCO-4
ADMITTED

RUCO 11.27 Refer to Mr. Dukes' rebuttal testimony at page 2.

a. Admit that UNSG provided no supporting calculations with its rebuttal testimony for its new over 2000% increase in its claim for cash working capital ($97,967 to $2,183,948). If your response is anything but an unqualified admission, explain fully.

b. Provide complete documentation including all Excel files and supporting calculations showing each payment relating to gas cost purchases from 1/1/2008 through the present.

c. Provide a copy of each gas purchase invoice from 1/1/2008 through the present.

d. Provide all payment documentation for each gas cost invoice from 1/1/2008 through the present.

e. Provide a copy of the current and prior gas purchase contracts and all amendments thereto affecting payment terms.

f. Identify the "primary purchased gas vendor" referred to on page 2, line 7.

g. When did the "primary purchased gas vendor" change its payment terms?

h. Provide all documents relating to the change in gas purchase payment terms including but not limited to all correspondence, letters, legal documents, tariff filings, invoices, emails.

i. Identify all credit limitations, referenced at page 2, line 10.

j. Provide all correspondence relating to all such credit limitations.

k. Explain in detail what UNSG could do to address each such "credit limitation"?

l. Identify, and provide a copy of, the specific provisions in the contract or agreement with the "primary purchased gas vendor" that allowed the vendor to change the payment terms.

m. Did UNSG contest or object to the change in payment terms? If not, explain fully why not. If so, provide all documents showing that UNSG objected to the change in payment terms.

n. Identify the payment terms that are related to each gas vendor that could provide gas supply to UNSG.

o. Identify all conditions that would allow UNSG to pay for purchased gas from the "primary purchased gas vendor" on a monthly basis.

RESPONSE:

a. UNS Gas provided supporting workpapers and calculations.

b. This information was provided with workpapers in UNS Gas' response to RUCO 10.1.

c. Please see RUCO 11.27(c & d), Bates Nos. UNSG(0571)09887 to UNSG(0571)10033, on the enclosed CD for the gas purchase invoices and payment documentation for the period 1/1/2008 through the present. This file contains gas purchase invoices for BP Energy, Transwestern Pipeline and EPNG. The file also includes a summary of each vendor's invoices (with payment detail). Mr. Dukes' Rebuttal Testimony included a revision of payment lag days for gas purchases. The revised payment lag days calculation included BP Energy invoices for 12/1/08 through 5/16/09 because the payment timing to this vendor **changed** from thirty (30) days to every two (2) weeks. The revised payment lag days calculation did not include additional invoices for Transwestern Pipeline or EPNG because the payment timing to those vendors did not change; however attached file includes invoices for Transwestern Pipeline and EPNG for your review, in addition to BP Energy invoices used in the payment lag days calculation revised for Mr. Dukes' rebuttal testimony. Invoices for the vendors included in the lead-lag study as originally filed are identified by Bates Nos. UNSG0571/01980 through UNSG0571/02063.

d. Please see UNS Gas' response to RUCO 11.27.c. above.

e. Current gas purchase contract: Base Contract for Sale and Purchase of Natural Gas between BP Energy Company and UNS Gas, Inc. dated September 1, 2008.

First Amendment to Base Contract for Sale and Purchase of Natural Gas between BP Energy Company and UNS Gas, Inc. dated November 18, 2008.

Prior gas purchase contract: Natural Gas Supply and Transmission Management Agreement by and between Citizens Communications Company, Arizona Gas Division and BP Energy Company, dated October 28, 2002, but effective as of October 1, 2002.

Pleas see RUCO 11.27(e), Bates Nos. UNSG(0571)10034 to UNSG(0571)10135, on the enclosed CD.

f. British Petrolium Energy Company.

g. January 2008 – March 2008, and November 2008 – May 2009.

h. Please see RUCO 11.27(h) (Confidential), Bates Nos. UNSG(0571)10138 to UNSG(0571)10144, on the enclosed CD.

For the winter season 2007/2008, see emails and the Standby Letter of Credit dated December 28, 2007.

For the winter season 2008/2009, see emails, Amendment to Base Contract dated November 18, 2008, and the Standby Letter of Credit dated October 30, 2008.

i. UNS Gas' primary purchased gas vendor (BP Energy) provides UNS Gas with an unsecured credit limit based upon its assessment of UNS Gas' creditworthiness. If the vendor's total exposure to UNS Gas exceeds that credit limit, it may decline to enter into additional transactions with UNS Gas until the exposure is below the credit limit, or it may request some form of performance assurance to cover the amount of the credit exposure in excess of the credit limit or to cover proposed new business. Such performance assurance may be in the form of a prepayment, a standby letter of credit, a performance bond, or a guaranty by another party.

Because UNS Gas is a winter-peaking gas distribution company, its exposure to its primary gas supplier is highest during the winter months of November through April. In each of the last two years, UNS Gas' exposure to BP Energy exceeded its credit limit. Therefore, UNS Gas negotiated terms to provide credit support in the form of more frequent payments (twice monthly) and a standby letter of credit, so that UNS Gas could continue to enter into new transactions with BP Energy.

j. Please see UNS Gas' response to RUCO 11.27.h above.

k. UNS Gas could make more frequent payments of amounts owed for gas supplied, could provide a standby letter of credit from a financial institution, or could curtail doing new business with the supplier, or a combination of these actions. The decision to provide a letter of credit vs. make prepayments depends on several factors including available credit under its revolving credit facility to issue letters of credit, the cost of issuing letters of credit, the amount of available cash on hand, and the interest rate that could be earned on the investment of excess cash.

l. Please see RUCO 11.27(e), UNSG(0571)10034 to UNSG(0571)10135,on the enclosed CD, and refer to Article IV—Security, of the Natural Gas Supply and Transportation Management Agreement dated October 28, 2002, and to Section 10.1—Financial Responsibility of the Base Contract dated September 1, 2008.

m. No, UNS Gas did not object to the change in payment terms. The vendor's request was reasonable in view of the size of the credit exposure compared to the credit limit provided, and therefore UNS Gas was willing to negotiate terms with the supplier that were agreeable to both parties.

n. Please see UNS Gas' response to Staff's first set of data requests, JMK 1-1, in which all lead-lag workpapers were provided.

o. As long as the vendor's total exposure to UNS Gas is within the credit limit established for UNS Gas, UNS Gas may pay for purchased gas on a monthly basis.

RESPONDENT: Barbara McCormick, Dallas Dukes, Janet Zaidenberg-Schrum (parts c and d)

WITNESS: Dallas Dukes, Kentton C. Grant

BEFORE THE ARIZONA CORPORATION C

EXHIBIT
RUCO- 5

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQEUST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783 DECISION NO. 70360 **OPINION AND ORDER**

DATES OF HEARING:	September 10, 11, 12, 13, 14, 20, 21, and October 2, 2007.
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Teena Wolfe[1]
IN ATTENDANCE:	William A Mundell, Commissioner Kristin A. Mayes, Commissioner
APPEARANCES:	Mr. Michael W. Patten and Mr. Jason Gellman, ROSHKA, DEWULF & PATTEN, PLC, on behalf of UNS Electric, Inc.; Ms. Michelle Livengood on behalf of Unisource Energy Services; Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office; Mr. Marshall Magruder, in propria persona; and Ms. Maureen Scott, Senior Attorney, and Mr. Kevin Torrey, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

[1] Administrative Law Judge Teena Wolfe conducted the hearing in this case and Administrative Law Judge Dwight Nodes drafted the Recommended Opinion and Order.

Service Fee Revenues

As discussed below in the Rate Design section of this Order, RUCO witness Marylee Diaz Cortez recommended that $48,648 should be added to the Company's revenues to reflect RUCO's claim that the proposed service fees for after-hours establishment and reconnection of service do not fully reflect the Company's actual costs (RUCO Ex. 8, at 21). UNSE witness D. Bentley Erdwurm stated that the Company shares RUCO's concerns regarding potential cross-subsidies, but the Company recommends that service fees be increased more gradually, consistent with the concept of gradualism (Ex. A-17, at 17).

We agree with UNSE's more gradual approach to increasing the service fees in question and therefore do not agree with RUCO's recommendation to adjust revenues.

Expenses

Payroll Expense

UNSE proposes an upward adjustment in its expenses of $339,184 to reflect known and measurable wage and salary increases that went into effect in 2007. Due to an oversight, the payroll expense increase proposal was not presented until the Company filed its rebuttal testimony. This amount includes normalized overtime expenses of $139,201, based on a two-year average including the test year and the year prior to the test year (Ex. A-25, at 11-12). UNSE contends that its adjustment only accounts for employee levels at the end of the test year and therefore does not create a mismatch. Company witness Dallas Dukes also claims that the Company's overtime normalization is consistent with the approach advocated by Staff in the recent UNS Gas case, which method was accepted by UNS Gas in that case (Ex. A-24, at 20).

Staff witness Ralph Smith testified that Staff opposes the increase recommended by UNSE. Staff claims that, with respect to the overtime adjustment, Mr. Smith's analysis is consistent with the position taken in the UNS Gas case, in which he used the lower of two calculations to reduce overtime costs for UNS Gas. In this case, Staff claims that Mr. Smith conducted the same calculations, one of which resulted in a reduction to overtime and the other showing an increase. Mr. Smith stated that "my analysis of overtime expense, which is presented in Attachment RCS-9, and which followed the same analysis format that I used in the UNS Gas case, indicates that the overtime expenses in UNS Electric's original filing is within a range of reasonableness (i.e., it was bracketed by the results of the two alternative calculations I performed). Consequently, no additional adjustment to overtime for UNS Electric is necessary." (Ex. S-58, at 45-6).

Staff also takes issue with the Company's overall proposed payroll adjustment. Staff argues that the proposed adjustment was not presented until UNSE's rebuttal testimony was filed on August 14, 2007, leaving very little time for Staff to conduct discovery and develop surrebuttal testimony, which was filed on August 24, 2007. Staff asserts that, in addition to the lateness of the adjustment, the Company's proposal is also inconsistent with treatment of payroll in the UNS Gas case, in which payroll was annualized to the end of the year but not beyond.

Although we understand Staff's concern that the Company's proposed adjustment was not presented until its rebuttal testimony was filed, we believe UNSE's proposal should be adopted because it reflects known and measurable payroll changes that went into effect more than a year ago. Mr. Dukes explained that the failure to include the payroll changes in the initial application was due to an oversight, and that the changes have been normalized to minimize a mismatch between the test year and the later payroll increases. We will therefore adopt the Company's recommendation on this issue.

Pension and Benefits Expense

UNSE proposed an upward adjustment to test year levels of pension and benefits expense of $82,965. RUCO witness Rodney Moore recommends removing a portion of these expenses, $11,612, because in a data response UNSE described that portion of the expenses as related to "gifts, awards, employee dinners, picnics and social events" (RUCO Ex. 5, at 12). Mr. Moore stated that RUCO considers these benefits to be an inappropriate burden on ratepayers (*Id.*).

UNSE witness Dukes responded that the expenses identified by RUCO are properly included in rates because they are "primarily related to the recognition of employee service, safety accomplishments and other goal achievements by individual or groups of employees" (Ex. A-25, at 18). He indicated that rewarding employees enables the Company to retain qualified employees and therefore provides a benefit to customers (*Id.*).

Consistent with our finding in the UNS Gas rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program. As RUCO points out, the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders. However, 40 percent of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area. For the same reasons, we also adopt Staff's recommendation to disallow 50 percent of the Officer's Long-Term Incentive Program (Ex. S-58, at 32). Given that the arguments raised in the UNS Gas case are virtually identical to those presented in this case, we see no reason to deviate from that recent Decision.

We also stated in Decision No. 70011 that although we believe, on balance, that the 50/50 sharing is reasonable, we share RUCO's concerns that the SRA offered to employees in 2005 may have the effect of undermining the very goals the PEP is intended to achieve (*i.e.*, providing an incentive for participating employees to improve performance and thereby benefit both the Company and its customers). As described by Mr. Moore, despite failing to meet the PEP goals, the UniSource Board of Directors decided nonetheless to provide the affected employees with a surrogate means of compensation. As we indicated in Decision No. 70011, it appears that the SRA sends a signal to employees that they will be compensated regardless of performance, which places the entire premise of the PEP at issue. We expect the program to be scrutinized in the Company's next rate case to determine the appropriateness of providing incentive compensation above base salaries to employees.

<u>Supplemental Executive Retirement Plan and Stock Based Compensation</u>

UNSE allows select executives to participate in a Supplemental Executive Retirement Plan ("SERP"). The SERP provides to eligible executives retirement benefits in excess of the limits allowed under Internal Revenue Service ("IRS") regulations for salaries in excess of specified amounts. UNSE contends that the $83,506 of test year SERP costs are reasonable and that neither Staff nor RUCO have shown that the Company's overall executive compensation costs are excessive or out of line with industry standards.

Staff and RUCO recommend disallowance of the SERP costs, in accordance with the Commission's Decision in the Southwest Gas case (Decision No. 68487, at 18-19). In that case, we disallowed Southwest Gas's SERP costs, finding:

> [T]he provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. (*Id.* at 19).

We disagree with the Company's argument that disallowance of the SERP costs effectively allows the IRS to dictate what compensation costs should be recovered. As was clearly stated in the passage cited above, and which passage was quoted in the UNS Gas case (Decision No. 70011, at 28), the issue is not whether UNSE may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent UNS Gas rate case,[9] and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

For these same reasons, we agree with Staff that test year expenses should be reduced to remove stock-based compensation to officers and employees. As Staff witness Ralph Smith stated, the expense of providing stock options and other stock-based compensation beyond normal levels of compensation should be borne by shareholders rather than ratepayers (Ex. S-58, at 34). The disallowance of stock-based compensation is consistent with the most recent rate case for Arizona Public Service Company (Decision No. 69663).

[9] *See also Arizona Public Service Co.*, Decision No. 69663, at 27 (June 28, 2007), and *Southwest Gas Co.*, Decision No. 68487, at 18-19 (February 23, 2006), wherein SERP costs were excluded in their entirety.

BEFORE THE ARIZONA CORPORATION C[illegible]

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COMMISSIONERS

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EXHIBIT
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ADMITTED

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.

DOCKET NO. G-01551A-07-0504

DECISION NO. 70665

OPINION AND ORDER

DATES OF HEARING:	June 13, 2008 (Procedural Conference); June 16, 17, 18, 20, 24, 25 and 26, 2008.
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Dwight D. Nodes
IN ATTENDANCE:	Mike Gleason, Chairman Jeff Hatch-Miller, Commissioner Kristin K. Mayes, Commissioner
APPEARANCES:	Ms. Karen S. Haller, Mr. Justin Lee Brown, and Ms. Meridith J. Strand, on behalf of Southwest Gas Corporation; Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office; Mr. Michael Grant, GALLAGHER & KENNEDY, P.A., on behalf of the Arizona Investment Council; Mr. Timothy Hogan, Arizona Center For Law In The Public Interest, on behalf of Southwest Energy Efficiency Project; and Ms. Maureen Scott, Senior Staff Counsel, and Mr. Charles Hains and Mr. Kevin Torrey, Staff Attorneys, Legal Division, on behalf of the Arizona Corporation Commission.

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Operating Expenses

2008 Wage Increase

In this proceeding, Southwest Gas has included in proposed test year expenses a 3 percent general wage increase that was given to employees in 2008, in addition to a wage increase given in 2007. Staff does not oppose recognition of the 2008 wage increase because it is a known and measurable post-test-year event. RUCO does not object to inclusion of the 2007 wage increases that became effective in May and June 2007 (after the end of the test year), but proposes to disallow the 2008 increases on the basis that they are too far removed from the end of the test year and would create a mismatch between rate base, revenues, and expenses at the end of the test year. (RUCO Ex. 3 at 23.)

Company witness Randi Aldridge testified that, contrary to RUCO's assertion, the Company included only wage increases for employees who were employed as of the end of the test year, to avoid a mismatch. (Ex. A-10 at 6-7.) She stated that the 2008 wage increase did not apply to any employee hired after the end of the test year (April 30, 2007); therefore, the number of employees at the end of the test year is synchronized with customers served during the test year. (*Id.* at 7.)

We agree with the Company and Staff that the 2008 wage increase expense should be allowed because it is a known and measurable expense that is being incurred by Southwest Gas on a going-forward basis. Because the post-test-year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenues and expenses. Our conclusion is consistent with the treatment accorded this issue in the Company's prior rate case. (*See* Decision No. 68487 at 12-13.)

American Gas Association Dues

The American Gas Association ("AGA") is a national trade association for natural gas distribution and transmission companies. During 2007, Southwest Gas paid to the AGA dues of $401,795, with the Arizona jurisdictional amount being 56.70 percent of the total ($227,920). (Staff Final Sched. C-6.) The AGA provides services to its members in the following categories: Advertising; Public Affairs; Corporate Affairs; General Counsel; General & Administrative Expense; Policy, Planning and Regulatory Affairs; Operations & Engineering Management; Policy & Analysis;

and Industry Finance & Administrative Programs. (Ex. A-11, RLA-2.)

In the Company's last rate case, Southwest Gas requested recovery of 96.36 percent of the AGA dues, excluding 3.64 percent of the dues related to the AGA's marketing and lobbying functions. In that case, Staff did not oppose the Company's request, but RUCO proposed disallowance of 39.09 percent of the AGA dues, to exclude the Communications and Public Affairs expense categories. The Commission rejected RUCO's proposed disallowance and adopted the Company's inclusion of 96.36 percent of the AGA dues, finding that "[a]lthough the descriptions of AGA activities provided by the Company [were] somewhat nebulous," Southwest Gas had satisfied its burden of showing that the AGA functions provide a benefit to the Company and its customers. (Decision No. 68487 at 14.) However, the Commission directed Southwest Gas to provide in its next rate case filing "a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its Arizona customers." (*Id.*)

In this case, Southwest Gas seeks recovery of 94.52 percent of its AGA dues, excluding 5.48 percent of the dues as related to marketing and lobbying functions. To satisfy the Commission's directive in the prior Decision, Company witness Aldridge provided testimony describing the AGA's functions, as well as several attachments extolling the virtues of various AGA activities. (Ex. A-10 at 21-24; Ex. A-11, RLA-1 and RLA-2.) The Company contends that it has provided ample support for the functions provided by the AGA and the benefits that accrue to the Company and its ratepayers as a result of the AGA's activities. Southwest Gas argues that the documentation provided comes directly from the AGA and that there is no better source of information for analyzing the appropriateness of the AGA's activities. The Company cites to the testimony of Ms. Aldridge who claimed that AGA member benefits amounted to $479 million, compared to only $18 million in total membership dues. (Ex. A-11 at 9.)

RUCO did not oppose the Company's proposed recovery of AGA dues in this proceeding. However, Staff recommends disallowance of 40 percent of AGA dues on the basis that Southwest Gas has not demonstrated how the AGA's activities provide specific benefits to ratepayers. Staff witness Ralph Smith stated that Southwest Gas failed to substantiate its claims that AGA membership resulted in $479 million in member savings in 2006, and that it is not clear if the claimed benefits have ever been audited or verified. (Ex. S-12 at 40; Ex. S-13 at 33.) Mr. Smith testified that the Company failed to demonstrate why ratepayers should fund activities through membership in an industry organization that would likely be disallowed if they were performed by the Company itself. (*Id.*) Staff's 40-percent disallowance recommendation is based on decisions by other state regulatory commissions and audits of the AGA by the National Association of Regulatory Utility Commissioners ("NARUC"). Mr. Smith cited to orders issued by other commissions in which AGA dues were disallowed in the following percentages: Michigan (16.17 percent), California (25 percent), and Florida (40 percent). (*See* Ex. S-12 at 41-45.) He also cited a 1999 NARUC-sponsored audit of AGA expenditures that stated, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit." (*Id.* at 43.)

Staff claims that its recommended 40-percent disallowance is consistent with a March 2005 NARUC Audit Report that quantified AGA function categories that Staff believes should not be paid by ratepayers. The categories cited by Staff are: Public Affairs (24.13 percent); Corporate Affairs and International (10.54 percent); half of General Counsel and Corporate Secretary (2.6 percent); and Marketing (2.37 percent). (*Id.* at RCS-2, Sched. C-6.) Staff contends that the 39.64-percent total represented by these activities supports its recommended disallowance. Moreover, according to Mr. Smith, based on the 2007 and 2008 AGA budgets, the recommended dues disallowance would be 43.29 percent and 46.19 percent, respectively (*Id.*; Ex. S-14 at 33-34.)

We find that Staff's recommended disallowance of 40 percent of AGA dues represents a reasonable approximation of the amount for which ratepayers receive no supportable benefit. The documentation offered by the Company to justify the AGA dues, including the alleged monetary savings to members, consists primarily of information provided by the AGA itself and must be viewed in that context. As Staff witness Ralph Smith indicated, several other states have disallowed AGA dues in substantially higher amounts than the amount proposed by Southwest Gas. Mr. Smith also pointed out that Staff's recommended disallowance is approximately the same percentage as that attained by totaling up AGA activities for Public Affairs, Corporate Affairs, half of General Counsel expenses, and marketing under a 2005 NARUC audit. Further, application of the 2007 and 2008

AGA dues would result in even greater disallowances under these categories. We therefore adopt Staff's recommendation to disallow 40 percent of the Company's AGA dues.

Injuries and Damages Expenses

Southwest Gas and Staff continue to dispute the appropriate amount to be allocated for injuries and damages expenses. The Company has proposed an increase in this expense of approximately $2,490,000, for a total of $8,169,000. Staff recommends reducing the Company's proposed increase to $1,638,000, for a total injuries and damages expense allowance of $7,317,000.

Southwest Gas contends that its proposal is consistent with the methodology agreed to by the parties, and adopted by the Commission, in the Company's last rate case. The Company's proposal utilizes claims in all jurisdictions over a 10-year period and includes recognition of a change in the Company's self-insurance limits during that period. Company witness Mashas testified that from January 1998 through July 2004, the Company's insurance policies provided that Southwest Gas was self-insured for up to $1 million of expenses related to a single claim. From August 2004 through July 2005, the Company provided self-insurance for the first $1 million per claim, and also for *aggregate* claims up to $10 million. In August 2005, Southwest Gas acquired an additional policy that covers aggregate claims for amounts between $5 million and $10 million. (Ex. A-16 at 3-4.)

According to Mr. Mashas, Southwest Gas has experienced only one incident since August 2004 in which the claim exceeded the $1 million per incident self-insured amount. The incident in question occurred in May 2005 when a leaking gas fire in Tucson caused several people to be severely burned, and Southwest Gas paid $10 million in a settlement of claims related to the incident. Southwest Gas argues that Staff's removal of this amount from its 10-year average is inappropriate because prior to August 2004, injuries and damages claims over $1 million would have been indemnified by the Company's insurer and would therefore not have been recorded on the Company's books. (*Id.* at 5.) Mr. Mashas claims that Staff's 10-year average is therefore skewed and is inconsistent with the treatment afforded injuries and damages expenses in the last rate case. Southwest Gas argues that Staff's exclusion of the $10 million claim does not reflect the level of self-insurance that the Company expects to experience during the period rates from this case are in effect.

Staff asserts that the $10 million payment related to the 2005 incident should be excluded

RUCO proposes disallowing 50 percent of MIP costs to recognize that both shareholders and customers receive a benefit from the performance goals included in the MIP. (RUCO Ex. 3 at 29.)

In the last Southwest Gas rate case, as well as several subsequent cases,[3] we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated:

> In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.

(*Id.*) We believe the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs.[4]

<u>Supplemental Executive Retirement Plan</u>

Southwest Gas also offers a Supplemental Executive Retirement Plan ("SERP") to select executives. The SERP provides supplemental benefits for high-ranking employees in excess of the limits placed by Internal Revenue Service ("IRS") regulations on pension plan calculations for salaries above specified amounts. (Ex. S-12 at 30-31.) We explained in the last Southwest Gas case:

> IRS regulations place limits on pension plan calculations for salaries exceeding $165,000 and thus salaries in excess of that level are not included in the pension calculation. Mr. Mashas stated that the SERP

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[3] *See UNS Gas, Inc.*, Decision No. 70011 (November 27, 2007) at 27; *Arizona Public Service Co.*, Decision No. 69663 (June 28, 2007) at 27; and *UNS Electric, Inc.*, Decision No. 70360 (May 27, 2008) at 21.

[4] On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ("SIP"). The costs related to similar incentive plans were recently rejected for APS and UNS Electric. (*See* Ex. S-12 at 32-34.) As was noted in the APS case, stock performance incentive goals have the potential to negatively affect customer service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price. (Decision No. 69663 at 36.)

> provides officers with a retirement benefit equal to 50 percent of the average of the last three years salary provided that they are at least 60 years old and have at least 20 years of service. In addition, IRS regulations place restrictions on the Company's 401(k) contributions to the extent that "maximum contribution levels represent a significantly smaller percentage of an officer's salary compared to other employees."

[Decision No. 68487 at 18 (citations omitted).]

Company witness Hobbs testified that the MIP, SIP and SERP are "key components of [the Company's] prudently managed total executive compensation expense and are vital to the Company's attraction and retention of highly-skilled employees, which ultimately benefits customers." (Ex. A-8 at 7-8.) She explained that the SERP is an "unqualified plan," and therefore payments are not guaranteed. She also stated that contrary to the testimony provided by Staff and RUCO, virtually every other gas and electric utility offers such employees a SERP, and the costs of the SERP are reasonable. (*Id.*)

Staff witness Smith and RUCO witness Moore recommend a total disallowance of SERP expenses. Mr. Smith cites to the prior Southwest Gas rate case, as well as the subsequent UNS Gas, APS, and UNS Electric cases, wherein the Commission disallowed SERP costs. Mr. Moore stated that SERP costs are not a necessary cost for providing service and indicated that the high-ranking officers covered by the SERP are already fairly compensated for their work and are provided a comprehensive array of benefits in addition to salaries. (RUCO Ex. 3 at 30.)

We agree with Staff and RUCO that the SERP expenses sought by Southwest Gas should once again be disallowed. We do not believe any material factual difference exists in this case that would require a result that differs from the Company's prior case. In that case, we stated:

> [W]e believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden

on ratepayers.

(Decision No. 68487 at 19.)

In the recent UNS Gas, APS, and UNS Electric cases, we followed the rationale cited above in disallowing SERP expenses. In Decision No. 70011, we indicated that SERP costs should not be recoverable and indicated:

> [T]he issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

[*Id.* at 28, (footnote omitted).] For these reasons, we agree with the recommendations of Staff and RUCO that the request for inclusion in rates of SERP expenses should be denied. We therefore adopt the recommendations of Staff and RUCO on this issue.

<u>Miscellaneous "Unnecessary" Expenses</u>

Based on his review of data requests, RUCO witness Rodney Moore proposed a disallowance of $185,210 from test year expenses for various miscellaneous expenses that RUCO deems unnecessary for the provision of service to the Company's customers. Mr. Moore testified that RUCO adjusted the Company's proposed operating expenses to remove payments to chambers of commerce and non-profit organizations; donations; club memberships; gifts; awards; extravagant corporate events; advertising; and various meals, lodging, and refreshments. (RUCO Ex. 3 at 27.) In his Surrebuttal Testimony, Mr. Moore cites the following specific miscellaneous expenses as examples of items that should not be recoverable: (1) massages ($2,160); (2) gift certificates to theaters, restaurants, and shopping malls ($18,230); (3) water, ice, coffee, beverages and refreshments for Company offices ($66,422); (4) breakfast, lunch, and dinner for meetings ($71,358); (5) off-site management meetings at various resorts ($8,835); and (6) a Board of Directors meeting at a golf course ($5,365). (*Id.* at 28; RUCO Ex. 6 at 7.)

Through her testimony, Company witness Randi Aldridge stated that RUCO had failed to

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
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COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. G-01551A-04-0876

DECISION NO. 68487

OPINION AND ORDER

DATES OF HEARING: October 3, 4, 5, 6, 7 and 11, 2005

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

IN ATTENDANCE: William A. Mundell, Commissioner
Marc Spitzer, Commissioner
Kristin K. Mayes, Commissioner

APPEARANCES: Mr. Andrew W. Bettwy, Ms. Karen S. Haller and Mr. Justin Lee Brown, on behalf of Southwest Gas Corporation;

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

Mr. Walter Meek, on behalf of the Arizona Utility Investors Association;

Mr. Peter Q. Nyce, Jr., on behalf of the United States Department of Defense;

Mr. Timothy M. Hogan, Arizona Center for Law in the Public Interest, on behalf of Southwest Energy Efficiency Project and Natural Resources Defense Council;

Ms. Laura Sixkiller, ROSHKA, DEWULF & PATTEN, PLC, on behalf of Tucson Electric Power Company; and

Mr. Jason Gellman and Ms. Diane Targovnik, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

We agree with Staff that the 2005 wage increase expense should be allowed because it is a known and measurable expense that is being incurred by the Company on a going-forward basis. Because the post-test year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenue and expenses.

American Gas Association Dues

The American Gas Association ("AGA") is a national trade association for natural gas distribution and transmission companies. During 2004, Southwest Gas paid dues to the AGA (Arizona portion) of $211,934 (RUCO Ex. 5, RLM-9). The AGA provides services to its members in the following categories: Public Affairs; Communications; Corporate Affairs and International; General Counsel and Corporate Secretary; Regulatory Affairs; Marketing Development; Operating & Engineering Services; Policy & Analysis; Industry Finance & Administrative Programs; and General & Administrative Expense (Ex. A-30, RLA-3).

Although Southwest Gas claims that it has removed the amount of the dues that are attributable to the AGA's Marketing and Lobbying functions (1.54 percent and 2.10 percent, respectively), RUCO seeks an additional 39.09 percent disallowance ($75,385) for the Public Affairs and Communications functions performed by the AGA (RUCO Ex. 5, RLM-9). According to RUCO witness Moore, the Communications category of AGA operations promotes the use of gas over other fuels, while the Public Affairs category provides members with information on legislative and regulatory developments, provides testimony, comments, and filings regarding legislative and regulatory activities, and lobbies on behalf of the industry (*Id.* at 21-22).

Southwest Gas witness Aldridge countered that the Communications and Public Affairs categories are appropriate AGA functions that should be recovered in test year expenses because the Company removed the amounts specifically associated with marketing and lobbying. Ms. Aldridge testified that the Communications function of the AGA includes developing informational materials for member companies and consumers and coordinating all media activity (Tr. 550). With respect to the Public Affairs function, the AGA described its activities as follows: "The [AGA] monitored and represented the activities of Congress and Federal agencies that affected issues of importance to the natural gas industry and its customers. This division also monitored state and local legislative and its management's compensation at risk. According to Southwest Gas, if the Company put these amounts in the employees' base salary, Staff and RUCO would not claim that there should be a disallowance.

In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.

Supplemental Executive Retirement Plan

Southwest Gas offers a Supplemental Executive Retirement Plan ("SERP") to the Company's officers. Company witness Mashas testified that the SERP is necessary "to ensure that the retirement and deferred compensation portions of [the officers'] total compensation are on parity with all other employees of Southwest whose retirement distribution is not impacted by certain IRS regulations" (Ex. A-33, at 3). Mr. Mashas claims that recovery of the SERP costs is reasonable due to restrictions on these employees' basic retirement plan ("BRP"), exclusion of deferred compensation from the BRP calculation, and the need to ensure attraction and retention of qualified employees. Mr. Mashas explained that IRS regulations place limits on pension plan calculations for salaries exceeding $165,000 and thus salaries in excess of that level are not included in the pension calculation. Mr. Mashas stated that the SERP provides officers with a retirement benefit equal to 50 percent of the average of the last three years salary provided that they are at least 60 years old and have at least 20 years of service (*Id.* at 5-6). In addition, IRS regulations place restrictions on the Company's 401(k) contributions to the extent that "maximum contribution levels represent a significantly smaller percentage of an officer's salary compared to other employees" (*Id.* at 4-5).

RUCO witness Moore proposed a reduction in test year expenses of approximately $2.7

million associated with the SERP. Mr. Moore stated the cost of these supplemental retirement benefits for select executives is not a necessary cost of providing gas service to customers because the Company's officers are already fairly compensated with a wide array of benefits, including a retirement plan. Mr. Moore cited to the Company's most recent rate case before the Nevada Public Utilities Commission[3] where Southwest Gas' SERP expenses were excluded from the Company's operating expenses (RUCO Ex. 5, at 28-29).

We agree with RUCO's position on this issue. Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

Miscellaneous Expenses

Through her Direct testimony, Company witness Aldridge indicated that the application included an adjustment to remove certain miscellaneous expenses for items such as gym memberships, donations and meals (Ex. A-29, at 23).

Based on his review of data requests, RUCO witness Moore proposed an additional adjustment to remove from test year expenses "payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events and for various meals, lodging and refreshments, which are not necessary in the provisioning of gas service" (RUCO Ex. 5, at 25).

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[3] *Application of Southwest Gas Corporation for Increase in Rates*, Public Utilities Commission of Nevada, Order in Docket No. 04-3011 (August 30, 2004), at 41.

EXHIBIT RUCO-8

BEFORE THE ARIZONA C[...]MISSION

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COMMISSIONERS

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

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

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

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

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

APPEARANCES:

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

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

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

Mr. Marshall Magruder, in propria persona; and

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

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BY THE COMMISSION:

On November 10, 2005, the Arizona Corporation Commission ("Commission") opened an inquiry (Docket No. G-04204A-05-0831) into the prudence of the gas procurement practices of UNS Gas, Inc. ("UNS" "UNS Gas" or "Company") ("Prudence Case").

On January 10, 2006, UNS filed an application (Docket No. G-04204A-06-0013) with the Commission seeking review and revision of the Company's Purchased Gas Adjustor ("PGA Case").

On July 13, 2006, UNS filed an application with the Commission (Docket No. G-04204A-06-0463) for an increase in its rates throughout the State of Arizona ("Rate Case").

On July 20, 2006, UNS filed separate Motions to Consolidate in each of the above-captioned dockets.

On August 14, 2006, the Commission's Utilities Division Staff ("Staff") filed a Letter of Sufficiency indicating that the Company's Rate Case application met the sufficiency requirements outlined in A.A.C. R14-2-103, and classifying the Company as a Class A utility.

On August 18, 2006, the Residential Utility Consumer Office ("RUCO") filed an Application to Intervene.

On September 8, 2006, a Procedural Order was issued consolidating the Prudence, PGA, and Rate Case dockets; scheduling a hearing for April 16, 2007; setting various other procedural deadlines; directing UNS to publish notice of the applications and hearing date; and granting RUCO's request for intervention.

On September 20, 2006, Arizona Community Action Association ("ACAA") filed a Motion to Intervene.

By Procedural Order issued November 15, 2006, ACAA's Motion to Intervene was granted.

On November 17, 2006, Marshall Magruder filed a Motion to Intervene on his own behalf.

By Procedural Order issued January 10, 2007, Mr. Magruder's request to intervene was granted.

With its rate application, UNS filed its required schedules in support of the application, as well as the direct testimony of James Pignatelli, David Hutchens, Kentton Grant, Dallas Dukes, Karen Kissinger, Gary Smith, Ronald White, and Tobin Voge.

On February 9, 2007, Staff filed the direct testimony of Ralph Smith, David Parcell, Robert Gray, Julie McNeely-Kirwan, and George Wennerlyn; RUCO filed the direct testimony of William Rigsby, Marylee Diaz Cortez, and Rodney Moore; ACAA filed the direct testimony of Miquelle Scheier; and Mr. Magruder filed his direct testimony.

On February 9, 2007, Staff filed a Request for Extension of Time to file the direct testimony of two of its witnesses.

On February 15, 2007, a Procedural Order was issued granting Staff's extension request, and revising the dates for responsive testimony for the other parties.

On February 16, 2007, Staff filed the direct testimony of Jerry Mendl.

On February 23, 2007, Staff filed the direct testimony of Steven Ruback.

On March 1, 2007, a Procedural Order was issued rescheduling the prehearing conference to April 13, 2007.

On March 16, 2007, UNS filed the rebuttal testimony of D. Bentley Erdwurm, Mr. Grant, Mr. Dukes, Ms. Kissinger, Mr. Hutchens, Mr. Pignatelli, Gary Smith, and Denise Smith.

On March 30, 2007, ACAA filed the surrebuttal testimony of Ms. Scheier.

On April 4, 2007, Staff filed the surrebuttal testimony of Mr. Gray, Ms. McNeely-Kirwan, Mr. Parcell, Mr. Ruback, Mr. Mendl, and Ralph Smith; RUCO filed the surrebuttal testimony of Mr. Rigsby, Mr. Moore, and Ms. Diaz Cortez; and Mr. Magruder filed his surrebuttal testimony.

On April 11, 2007, UNS filed the rejoinder testimony of Denise Smith, Gary Smith, Mr. Pignatelli, Ms. Kissinger, Mr. Dukes, and Mr. Erdwurm.

On April 13, 2007, a prehearing procedural conference was conducted to address the order of witnesses and exhibits.

The evidentiary hearing commenced as scheduled on April 16, 2007, and additional hearing days were held on April 17, 18, 19, 20, 24, and 25, 2007. At the close of the hearing, a briefing schedule was established, with initial briefs due on May 31, 2007, and reply briefs due on June 14, 2007.

On May 30, 2007, Staff filed a Request for Extension of Time to File Initial Brief.

On May 31, 2007, a Procedural Order was issued granting Staff's extension request and directing initial and reply briefs to be filed by June 5 and June 19, 2007, respectively.

Initial briefs were filed on June 5, 2007, by UNS, Staff, RUCO, and Mr. Magruder. Final Schedules were also filed on June 5, 2007, by UNS and RUCO.

On June 6, 2007, Staff filed a Notice of Errata and Revised Initial Brief.

Reply Briefs were filed on June 19, 2007, by UNS, Staff, RUCO, and Mr. Magruder.

On June 21, 2007, Staff filed a Notice of Errata and Additional Authority.

Rate Application

According to the Company's application, as modified, in the test year ended December 31, 2005, UNS had adjusted operating income of $8,506,168,[1] on an adjusted Original Cost Rate Base ("OCRB") of $162,358,856, for a 5.24 percent rate of return. UNS requests a revenue increase of $9,459,023; Staff recommends a revenue increase of $4,312,354; and RUCO recommends an increase of $2,734,443. A summary of the parties' positions follows.

	Company Proposed	Staff Proposed	RUCO Proposed
ORIGINAL COST			
Adjusted Rate Base	$162,358,856	$154,547,272	$144,646,160
Rate of Return	8.80%	8.12%	8.22%
Req'd Operating Inc.	14,284,546	12,549,238	11,889,914
Op. Income Available	8,506,168	9,900,380	10,219,499
Operating Inc. Def.	5,778,378	2,648,858	1,670,416
Rev.Conver. Factor	1.6370	1.6370	1.6370
Gross Rev. Increase	9,459,023	4,336,098	2,734,443
FAIR VALUE			
Adjusted Rate Base	$191,875,209	$184,063,625	$171,189,139
Rate of Return	7.44%	6.81%	6.95%
Req'd Operating Inc.	14,284,546	12,534,733	11,889,914
Op. Income Available	8,506,168	9,900,380	10,219,499
Operating Inc. Def.	5,778,378	2,634,353	1,670,416
Rev.Conver. Factor	1.6370	1.6370	1.6370
Gross Rev. Increase	9,459,023	4,312,354[2]	2,734,443

[1] The Company's "Final Schedules," which were submitted at the time UNS' initial brief was filed, are inconsistent with the revenue requirement recommendations set forth in the Company's brief (compare, *e.g.*, UNS Initial Brief at 5-6 and Final Schedule A-1). No subsequent filings were submitted to explain the differences between these documents and the reason for the discrepancy is unknown. For purposes of this Decision, we have used the Company's "Revised Schedules," (admitted at the hearing as Ex. A-10), and as set forth in its brief.

[2] Staff's gross revenue increase was calculated by applying a zero cost value to the "excess" between OCRB and FVRB.

REVENUE REQUIREMENT

Rate Base Issues

UNS proposed an OCRB of $162,358,856; Staff recommends an OCRB of $154,547,272; and RUCO proposed an OCRB of $144,646,160. Each of the disputed issues regarding rate base items is discussed below.

Construction Work in Progress

Construction work in progress ("CWIP") is a regulatory concept under which, in limited circumstances, a regulatory body allows recovery in a company's rate base of plant that was under construction during the test year but not used and useful for purposes of serving customers. In this proceeding, UNS Gas seeks inclusion of approximately $7.2 million of CWIP (which would provide the Company with approximately $1.5 million in additional annual revenues). In support of its position, UNS argues that CWIP is an accepted aspect of ratemaking that has been used in many states and that the Arizona Supreme Court previously upheld the allowance of CWIP, citing *Arizona Community Action Assoc. v. Arizona Corp. Comm'n*, 123 Ariz. 228, 230, 599 P.2d 184, 186 (1979). In that case, the Arizona Supreme Court stated that allowing CWIP "appears to be in the public interest to have stability in the rate structure within the bounds of fairness and equity rather than a constant series of rate hearings." (*Id.*).

UNS contends that it will not be able to earn its authorized rate of return even if its full rate request is granted in this case, due to the high rate of growth in its service area, which requires higher levels of capital investment to serve new customers. According to Company witness Kentton Grant, because investment in new plant creates additional fixed costs and because growth leads to capital requirements in excess of the Company's internal cash flow, the impact of regulatory lag on UNS Gas is more severe than for many other utilities (Co. Ex. 28 at 9; Co. Ex. 27 at 28). Mr. Grant testified that in 2006 UNS added $17 million in net plant, which resulted in an additional $3 million in fixed costs (*e.g.*, depreciation, property taxes), but new customers added in 2006 provided only $1.8 million in new revenues, resulting in a net loss of $1.2 million for UNS associated with serving growth in 2006 (Co. Ex. 28 at 10, Attach. KCG-10).

Staff and RUCO oppose inclusion of CWIP in the Company's rate base. Staff witness Ralph Smith stated that, although the Commission has previously allowed CWIP in rate base, the Commission's general practice has been not to allow CWIP. In support of Staff's disallowance recommendation, Mr. Smith claims that absent compelling reasons, which have not been shown by UNS in this case, there is no valid reason to grant CWIP. Mr. Smith asserts that the Company has not demonstrated that its test year CWIP balance was for non-revenue-producing and non-expense-reducing plant. He testified that much of the construction appears to be for mains, services, and meters related to serving customer growth, which plant is therefore revenue producing. Mr. Smith stated that, although test year revenues have been annualized to (2005) year-end customer levels, revenues have not been extended beyond the test year to correspond to customer growth. Thus, according to Mr. Smith, inclusion of CWIP in rate base, without recognition of the incremental revenue the plant supports, would cause a mismatch for regulatory purposes (Ex. S-25 at 9-10).

RUCO witness Marylee Diaz Cortez also recommends disallowance of CWIP for many of the same reasons cited by Staff witness Ralph Smith. Ms. Diaz Cortez stated that the Commission has previously allowed CWIP only in extraordinary circumstances, which she claims are not present in this case. She claims that recovery of earnings on CWIP plant balances prior to the plant becoming used and useful is accomplished through an Allowance for Funds Used During Construction ("AFUDC"), through which the Company may accrue interest on the CWIP balances. The AFUDC accruals are ultimately recovered over the life of the plant through depreciation expense once the asset becomes used and useful in provision of utility service (RUCO Ex. 5, at 7-9). Ms. Diaz Cortez testified that regulatory lag has always been a characteristic of rate of return regulation and that such lag may also provide a benefit to the Company, to the extent that plant retirements, accumulated depreciation, and expired amortizations allow it to earn a return on those items between rate cases. She also stated that the growth phenomenon in the UNS service area has a positive aspect due to the increase of revenues associated with serving new customers (*Id.* at 9-10).

We agree with Staff and RUCO that the request for CWIP in this case is not supported by the record. As the Staff and RUCO witnesses indicated, UNS is not faced with an extraordinary situation that would justify inclusion of CWIP in rate base because the plant required to serve new customers will help produce revenues; UNS has a means, through accrual of AFUDC, to mitigate the effect of the CWIP investment; allowance of CWIP would undermine the balancing of test year revenues and expenses; and the regulatory lag inherent in utility regulation may provide benefits to the extent that items such as plant retirements and accumulated depreciation occur between test periods and thereby help to mitigate periods of higher plant investment associated with customer growth.

As Staff points out in its brief, one of the few instances in which the Commission previously allowed inclusion of CWIP in rate base occurred in 1984 in a case involving Arizona Public Service Company ("APS"). In that case, the Commission addressed the need for a CWIP allowance due to extraordinary circumstances involving the Palo Verde nuclear plant. The Commission allowed approximately $200 million of APS's $600 million CWIP balance as a means of addressing a critical cash-flow deficiency, and as a means to lessen the severe rate shock that would be experienced by customers if the entirety of the nuclear plant were placed in rate base at one time.[3] Staff argues that UNS is not faced with a comparable cash-flow crisis, and that the $7 million of CWIP requested by the Company does not present a rate shock concern that would justify inclusion of CWIP in this case. We therefore decline the Company's request for rate base recognition of CWIP in this proceeding.

Post-Test-Year Plant

UNS proposes that, if its request for CWIP is denied, the Commission should alternatively allow inclusion of post-test-year plant in rate base. The Company argues that the Commission has approved post-test-year plant in a number of recent cases, and UNS faces faster growth than many other utilities in Arizona. Therefore, UNS argues that, absent inclusion of CWIP, the Commission should recognize inclusion of post-test-year plant.

Staff opposes the Company's proposal for reasons similar to the arguments raised on the CWIP issue. Staff witness Ralph Smith testified that the post-test-year plant arguments suffer from the same flaws as the request for inclusion of CWIP. He stated his belief that recognition of post-test-year plant would be imbalanced because it fails to capture post-test-year revenue growth and decreases in maintenance costs associated with the new plant (Ex. S-27 at 14-15).

[3] *Arizona Public Service Co.*, Decision No. 54247 (November 28, 1984), at 19-20.

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

<u>Deduction of Customer Advances</u>

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

UNS argues that it is inherently unfair to exclude the advances from rate base if the plant associated with those advances is not yet in service and not included in rate base. UNS claims that the purpose of deducting advances (*i.e.*, recognizing customer-supplied capital) is not furthered when the plant is not in service. The Company also contends that the deduction of advances in this case would discourage utilities from seeking advances to offset infrastructure capital costs.

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

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

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

As we have stated in prior cases, regulated utility companies control the timing of their rate case filings and should not be heard to complain when their chosen test periods do not coincide with the completion of plant that may be considered used and useful and therefore properly included in rate base. We believe our conclusions regarding UNS's CWIP-related proposals are entirely consistent with the treatment that has been afforded to other utility companies regulated by the Commission and provide a result that is fair to both the Company and its customers.

Geographic Information System

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

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

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

We agree with Staff and RUCO that the GIS costs are not properly recoverable as a regulatory asset in this proceeding. As described by Staff witness Ralph Smith, the GIS costs were required by GAAP to be expensed, and the vast majority of those costs were incurred prior to the test year and are non-recurring in nature (Ex. S-25 at 12-17). Further, the Company's failure to seek an accounting order from the Commission when the costs were incurred renders them unrecoverable as a regulatory asset. As Mr. Smith points out, it is not unusual for investors to be responsible for expenses incurred between test years, just as the utility's investors may benefit from cost decreases and increased revenues during the same period (Ex. S-27 at 16-19). As both Staff and RUCO contend, there is nothing inherently unfair about the treatment afforded to the GIS costs in this case because costs and revenues are ever changing, and moreover, the improved efficiencies touted by UNS as a result of the GIS inure to the benefit of the Company's investors at least as much as to ratepayers. Finally, any blame for UNS's inability to recover those costs through rates lies with the Company's prior failure to properly account for the costs under GAAP accounting standards.

Plant in Service

Although Staff did not challenge the Company's proposed plant-in-service amounts, RUCO recommends the disallowance of approximately $3.1 million in plant that it considers unsubstantiated. UNS claims that it provided adequate documentation for the plant, but RUCO contends that the Company failed to provide records supporting increased plant balances recorded on the books of Citizens Utilities between the end of the last test year (December 31, 2001) and the date the Company acquired the system from Citizens (August 11, 2003).

According to RUCO, Citizens' gas plant in service was approximately $234 million at the end of 2001, and UNS has records to support $10.7 million of additional plant in service between the end of 2001 and June 30, 2003 (Ex. A-8 at 2; RUCO Ex. 1). RUCO claims that UNS has no records to support additional plant in service as of the date of the transfer, yet the Company booked approximately $248 million of plant in service as of the acquisition date of August 11, 2003 (Tr. at 192-93). UNS witness Karen Kissinger testified that certain electronic files provided to RUCO supported the higher plant value, but conceded that those files do not provide a means of reconciling the plant balances claimed as of the acquisition date (*i.e.*, $248 million) (Tr. at 194-95, 214). RUCO also disputes the Company's argument that the higher plant balances were approved by the Federal Energy Regulatory Commission ("FERC"), based on Ms. Kissinger's concession that the submission to FERC was not a request for approval of the specific plant amounts, but simply a request for confirmation from FERC that the amounts are recorded to the proper FERC accounts (Tr. at 198). Based on the evidence presented, RUCO requests a decrease of $3,133,264 in the Company's proposed plant in service and a corresponding increase in accumulated depreciation of $3,857,413, (RUCO Ex. 3 at 12).

UNS contends that it provided adequate documentation to support its claimed plant-in-service balances for the period in question. The Company argues that, because Citizens was scrambling to wrap up its accounting for the final months at the time the sale was being finalized, it is not surprising that Citizens' records from that period were less extensive than normal (Tr. at 194-97). UNS relies on the electronic files provided to RUCO to support its position. The Company also points to testimony by RUCO witness Rodney Moore, who agreed that "records from Citizens are notoriously inadequate for a determination of the actual value of the pre-acquisition gross plant and accumulated depreciation" (RUCO Ex. 4 at 4). UNS asserts that other companies seeking post-acquisition approval of plant values based on Citizens' inadequate records have not been subject to downward adjustments[4], and that imposing downward adjustments on UNS would be inequitable. UNS also claims that the Commission's order approving the sale of the Citizens gas system assets to UNS did not include record retention requirements, although such requirements had been included in prior Commission Orders such as those related to the sale of Southern Union Gas Company's assets to Citizens (Ex. A-7 at 6).[5] Another argument raised by UNS is that it directly transferred the final plant-in-service values from Citizens' books to its own at the time of the acquisition. The Company contends that FERC's approval of UNS's accounting procedures and a subsequent audit of the Company's financial statements further support its claim that its proposed plant-in-service value is appropriate.

We find that UNS has explained adequately the basis for its plant-in service-proposal. As UNS witness Kissinger indicated in her rebuttal testimony, the acquisition of the Citizens assets was accounted for by UNS in accordance with applicable accounting standards, and the Company obtained a clean audit opinion regarding its financial statements from PricewaterhouseCoopers for the applicable period following the acquisition (Ex. A-7 at 2; Ex. A-6, Attach. KGK-1). The Company's accounting treatment was also approved by the accounting entries associated with the

[4] *See, e.g., Arizona –American Water Co.*, Decision No. 67093 (June 30, 2004).
[5] Decision No. 57647 (December 2, 1991), at 14.

acquired plant (Ex. A-7 at 4). UNS Gas provided sufficient documentation to support the amount of plant in service transferred from Citizens, and we therefore reject RUCO's proposed adjustment to plant in service.

Test Year Accumulated Depreciation

RUCO has also proposed increasing the Company's accumulated depreciation by approximately $2,855,454, due to RUCO's assertion that UNS improperly applied depreciation rates that were requested in the last rate case (Docket No. G-01032A-02-0598). That case was later suspended and combined with a joint application between UNS and Citizens for acquisition of the Citizens assets by UNS. The consolidated dockets ultimately resulted in a settlement agreement that was approved in Decision No. 66028 (July 3, 2003). RUCO argues that, because the settlement approved in Decision No. 66028 did not specifically mention new depreciation or amortization rates, UNS should apply the depreciation rates approved in the prior Citizens gas rate case in Decision No. 58664 (June 16, 1994). RUCO witness Moore cited to A.A.C. R14-2-102(C)(4), which states that changed depreciation rates shall not become effective until the Commission authorizes such changes. (RUCO Ex. 3 at 13-14). Accordingly, Mr. Moore proposed that test year accumulated depreciation should have been calculated as approved in the prior Citizens rate case, resulting in a reduction to the Company's OCRB of $2,855,454 (*Id.* at 14).

UNS argues that RUCO's recommendation fails to recognize that the Commission approved new depreciation rates in Decision No. 66028 which, as noted above, approved the sale of Citizens' gas system assets to UNS and approved a rate increase pursuant to the terms of a settlement agreement. Although the Commission did not explicitly approve new depreciation rates in Decision No. 66028, UNS contends that the settlement agreement contained a specific schedule showing how the revenue requirement was calculated. UNS witness Kissinger testified that the depreciation rates that formed the basis of the settlement were approved by the Commission and that no party objected to the depreciation rates in that case (Ex. A-7 at 9). Ms. Kissinger also attached to her testimony the schedule that formed the basis of the revenue requirement and explained on cross-examination that the updated depreciation expense adjustment was subsumed within operating expenses in the settlement agreement schedule (*Id.* at Attach. KGK-11; Tr. at 201-03).

We agree with UNS that the depreciation rates contained within the revenue requirement schedules, and attached to the settlement agreement, were implicitly approved in Decision No. 66028. Although Decision No. 66028 approved a "black box" settlement, in the sense that the specific revenue requirement issues were not discussed individually, the basis of the underlying revenue requirement was attached to the settlement agreement, and no party objected to the individual components of that revenue requirement. Accordingly, it was reasonable for UNS to apply the accumulated depreciation rates that were a component of the settlement. Indeed, RUCO witness Diaz Cortez admitted that the prior Citizens rate case order (Decision No. 58664) contained a specific discussion of only 2 of the 28 depreciation accounts and that it would thus be necessary to refer to the underlying application even in that case to ascertain the specific depreciation rates that were approved by the Commission in that order (Tr. at 673-74). We therefore reject RUCO's recommendation on test year accumulated depreciation.

Working Capital

As described by UNS witness Karen Kissinger, working capital is generally defined as "investor funding in excess of the balance of net utility plant reflected in rate base that is required for the provision of utility service" (Ex. A-6 at 10). The components of working capital include materials and supplies, prepayments, and cash working capital. The amounts for materials and supplies, and prepayments, are determined based on test year recorded balances, whereas the cash working capital component was determined by UNS based on a lead-lag study (*Id.* at 10-11).

Staff witness Ralph Smith summarized the concept of cash working capital as follows:

> Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation, a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds (Ex. S-25 at 18-19).

Based on Staff's proposed adjustments, Mr. Smith proposed a corresponding adjustment to the Company's cash working capital requirements. Staff's recommendation results in a cash working capital requirement of negative $268,272, in accordance with Staff's other recommendations in this case (Ex. S-27 at 20, Attach. RCS-2S).

In its initial brief, UNS points out that a number of ratemaking adjustments will have an effect on the Company's working capital requirement. UNS also contends that RUCO's proposed working capital proposal should be rejected because RUCO failed to use a simultaneous equation to compute two elements of cash working capital: synchronized interest and current income taxes (Ex. A-7 at 12).

In its reply brief, RUCO responded that its schedules did account for synchronized interest in both the working capital and income tax calculations. RUCO cites to Mr. Moore's schedules to support its claim (RUCO Ex. 3, Sched. RLM-3, Line 15; Sched. RLM-14, Lines 3, 8, and 18; and Sched. RLM-6, Line 8).

It does not appear from the record that the parties are in disagreement with regard to the underlying working capital requirements, subject to the various adjustments that necessarily flow from the revenue requirement established in this Decision. The working capital requirement has been determined in accordance with the revenue requirement established in this Order.

<u>Accumulated Deferred Income Tax</u>

Based on its recommendations in this case, Staff adjusted rate base by $195,336 to account for removal of accumulated deferred income tax ("ADIT") related to the GIS deferral issue, removal of ADIT related to the Supplemental Executive Retirement Plan, and removal of 50 percent of the ADIT related to incentive compensation (Ex. S-25 at 19). Staff claims that UNS did not contest these ADIT adjustments, which Staff asserts are necessary to reconcile rate base with the components of operating income adjustments.

In its brief, UNS does not address the ADIT issues raised by Staff, which are reconciliation adjustments flowing through from several operating income issues and are addressed below. However, the Company does take issue with RUCO's alleged failure to make corresponding adjustments to ADIT and deferred income tax expense (Ex. A-7 at 11-12). Because RUCO did not address this issue in its briefs, presumably, it does not oppose the Company's position.

Based on the record before us, we agree that the appropriate reconciliation adjustments should be made to reflect the effect on ADIT and income tax expense in accordance with this Decision.

Summary of Rate Base Adjustments

Based on the foregoing discussion, we adopt an adjusted OCRB of $154,604,408 and a Fair Value Rate Base ("FVRB") of $184,120,761.

	Commission Approved
ORIGINAL COST:	
Gas Plant in Service	$271,980,463
Less: Accumulated Depreciation	(72,006,708)
Net Plant in Service	199,973,755
Citizens Acquisition Discount	(30,709,738)
Less: Accum. Amort. – Citizens Acq. Disc.	(1,876,981)
Net Citizens Acq. Discount	(28,832,757)
Total Net Utility Plant	171,140,998
Deductions:	
CIAC	(7,283,595)
Customer Deposits	(3,040,484)
Accum. Deferred Income Taxes	(6,289,473)
Allowance for Working Capital	(211,136)
Regulatory Liabilities	(19,721)
Total Deductions	(16,844,409)
Additions:	
Regulatory Assets	307,819
Total OCRB	$154,604,408
RCND[6] RATE BASE:	
Gas Plant in Service	$367,054,190
Less: Accumulated Depreciation	(97,114,865)
Net Plant in Service	269,939,325
Citizens Acquisition Discount	(41,822,562)
Less: Accum. Amort. – Citizens Acq. Disc.	(2,560,308)
Net Citizens Acq. Discount	(39,262,254)
Total Net Utility Plant	230,677,071
Deductions:	
CIAC	(7,786,962)
Customer Deposits	(3,040,484)
Accum. Deferred Income Taxes	(6,289,473)
Allowance for Working Capital	(211,136)
Regulatory Liabilities	(19,721)

[6] Reconstruction New (less) Depreciation

Total Deductions	(17,347,326)
Additions:	
Regulatory Assets	307,819
Total RCND	$213,637,114

FAIR VALUE RATE BASE:

Gas Plant in Service	$319,517,327
Less: Accumulated Depreciation	(84,560,787)
Net Plant in Service	234,956,540
Citizens Acquisition Discount	(36,266,150)
Less: Accum. Amort. – Citizens Acq. Disc.	2,218,645
Net Citizens Acq. Discount	(34,047,505)
Total Net Utility Plant	200,909,035
Deductions:	
CIAC	(7,535,279)
Customer Deposits	(3,040,484)
Accum. Deferred Income Taxes	(6,289,473)
Allowance for Working Capital	(211,136)
Regulatory Liabilities	(19,721)
Total Deductions	(17,096,093)
Additions:	
Regulatory Assets	307,819
Total FVRB	$184,120,761

Operating Income Issues

In the test year, the Company's reported operating revenues were $47,169,528, with reported adjusted test year operating expenses of $38,740,547, and test year net operating income of $8,428,981. As reported in its Surrebuttal Schedules, Staff's proposed adjusted test year operating revenues were $47,273,923, with adjusted test year operating expenses of $37,373,543, resulting in test year net operating income of $9,900,380. RUCO's Final Schedules show proposed adjusted test year operating revenues of $50,014,877, with adjusted test year operating expenses of $38,124,962, yielding test year net operating income of $11,889,914. The disputed expense adjustments are discussed below.

Revenues

Customer Annualization

UNS has proposed in this case to calculate customer revenue annualization based on a cyclical growth pattern, which the Company contends more accurately reflects its actual experience in its service territory. Company witness D. Bentley Erdwurm described the traditional approach of customer annualization as a comparison of customer counts in each month of the test year to the end of test year level of customers. Under this approach, the additional customers attributable to each month are multiplied by the average revenue per customer for each month to obtain the additional revenue attributable to the additional customers (Ex. A-20 at 2). Mr. Erdwurm testified that the traditional method works well when growth is steady and additional customers are similar in size to existing customers, but breaks down when a company, such as UNS, experiences cyclical seasonal growth (*Id.*). He conceded that the Commission has never before adopted a revenue annualization method such as the one advocated by UNS. However, he contends that the Company's proposed methodology is appropriate in this case because "in cases of cyclical growth, the mathematics break down and...[the traditional method] will often give you a totally counterintuitive result, where you would actually have a negative customer adjustment on a growing system" (Tr. at 447).

Staff and RUCO oppose adoption of the Company's annualization proposal. RUCO argues that although the Company's customer levels are somewhat seasonal, they do not exhibit a degree of seasonality or produce an aberrational result that would make the traditional method inappropriate. Ms. Diaz Cortez pointed out that the customer base for UNS's largest rate schedule, R10, increased from month to month for every month except April, May, and July, and that the decreases in those months ranged from .09 percent to .28 percent (RUCO Ex. 6 at 12, Sched. MDC-1). RUCO asserts that these changes do not exhibit an extreme level of seasonality that would justify departure from the traditional method advocated by RUCO and Staff.

Staff witness Ralph Smith testified that the traditional method of customer annualization has been effective in coordinating the revenue element of the ratemaking formula with other components, such as rate base, and that many of the Company's arguments are without merit (Ex. S-27 at 19-21). According to Mr. Smith, any method for determining an annualization adjustment should be transparent and straightforward to allow replication and verification of the results. He contends that while the traditional method satisfies these criteria, UNS's proposal to apply percentage growth factors instead of customer bill counts is difficult to follow and replicate and actually appeared to understate growth (*Id.* at 24).

We agree with Staff and RUCO that UNS has not presented a valid case for departing from the traditional method of calculating customer revenue annualization. Although the Company's arguments may have some validity in a theoretical sense, adoption of the cyclical methodology is not warranted in this proceeding. RUCO and Staff highlighted some of the flaws inherent in the Company's proposal, including the lack of any significant demonstrated seasonality, the complexity of the formula, lack of transparency, and the claim by the Staff witness that the methodology may actually result in an understatement of revenues. We therefore decline to adopt UNS's revenue annualization proposal.

Weather Normalization

Staff witness Ralph Smith stated that Staff's weather normalization adjustment increases retail revenue by $1,962, compared to UNS's proposal, because, in Staff's annualization, the weighted average number of customers exceeded the level reflected in the Company's corresponding annualization. Mr. Smith claims that both the Staff and UNS weather normalization adjustments reflect an increase to revenue due to warmer than normal temperatures during the test year (Ex. S-27 at 25).

In its brief, UNS states that the weather normalization adjustment should reflect the other positions taken herein, including the customer annualization adjustment proposed by the Company.

Although RUCO accepts the Company's proposed weather normalization, it proposes a further adjustment of $900 related to the additional customers/revenue the Company proposes be recognized as a result of its customer annualization proposal (RUCO Ex. 6 at 16).

It is not entirely clear whether the weather normalization issue remains in dispute given our determination above that the Company's customer annualization recommendation should not be adopted. To the extent that there is any remaining disagreement on this issue, we adopt Staff's weather normalization recommendation in accordance with the discussion above regarding customer annualization.

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Expenses

Legal Expenses Related to FERC Rate Case

During the 2005 test year, UNS incurred legal expenses of $311,051 related to settlement discussions involving an El Paso Natural Gas Company ("El Paso") FERC rate case. The El Paso case eventually settled, and due to the non-recurring nature of those legal expenses, both Staff and RUCO recommended removal of that amount from allowable expenses in this case (Ex. S-15 at 30; RUCO Ex. 5 at 21).

UNS witness Dallas Dukes testified that Staff's and RUCO's recommendations would set the Company's legal expenses at an amount well below the expected ongoing level (Ex. A-13 at 17). As an alternative, he proposed an allowance of $430,777 (pre-tax), which represents a two-year average of legal expenses actually incurred by UNS for 2004 and 2005 (*Id.* at 18). Mr. Dukes stated that the actual legal expenses incurred by UNS were $373,174 for 2004, $488,380 for 2005, and $425,540 for 2006, and that its projected legal expenses for 2007 are $425,208 (*Id.*; Ex. A-14 at 9).

We believe that the Company's allowable legal expenses should be set at a level that reflects more accurately its actual experience, both historical and anticipated. Staff and RUCO make a valid argument that the legal expenses incurred during 2005 were higher than normal due to the Company's participation in the El Paso rate case and that such expenses are likely non-recurring in nature. However, the RUCO and Staff recommendations fail to recognize that even after completion of the El Paso case, UNS incurred legal expenses of more than $400,000 in 2006 and is expected to do so again in 2007, legal expenses of in each year. Thus, even if 2005 is removed as an anomaly, actual legal expenses for 2004 and 2006 and projected legal expenses for 2007 produce an average of slightly more than $400,000 per year. We therefore believe it is reasonable, based on the record, to allow legal expenses of $400,000 to UNS in this case.

Rate Case Expense

UNS initially requested inclusion of $600,000 for rate case expense, amortized over three years. However, in his rebuttal testimony, Mr. Dukes amended the request to $900,000, amortized over three years, based on the Company's claim that UNS had already incurred almost $800,000 in costs related to pursuing its rate case (Ex. A-13 at 34-35). UNS contends that the proposals offered by Staff and RUCO ($255,000 and $251,000, respectively), which are based primarily on comparisons to the recent Southwest Gas rate case (Decision No. 68487), are deficient because they fail to recognize that Southwest Gas used internal personnel and support services, internal costs that are built into Southwest Gas' rate base. In comparison, UNS does not have in-house legal or rate departments, but instead relies heavily on the rate and legal personnel of Tucson Electric Power Company ("TEP") to prosecute its rate cases. Mr. Dukes testified that an allocation from TEP for such costs ensures that TEP customers do not subsidize UNS operations (*Id.*; Ex. A-14 at 9-11). Mr. Dukes added that UNS Gas received more than twice as many data requests as did Southwest Gas (Tr. at 632).

RUCO witness Moore stated that RUCO's recommendation in this case is appropriate based on a comparison to the recent Southwest Gas rate case, in which the approved rates included an allowance for $235,000 allocated over three years (RUCO Ex. 3 at 25-26). RUCO contends that the UNS case shares similar characteristics with the Southwest Gas case in that both companies extensively used in-house staff, both companies requested approval of a decoupling mechanism and PGA revisions, and both cases covered a comparable number of hearing days (*Id.*; Tr. at 655). RUCO therefore recommends a rate case expense allowance of $251,000, amortized over three years.

As indicated above, Staff recommends a rate case expense allowance of $255,000, amortized over three years, based on Staff's view that the Southwest Gas case raised many of the same issues addressed in this proceeding. Staff witness Ralph Smith disputed the rationale offered by UNS for its proposed rate case expense. Mr. Smith stated that although this may be the first rate case for this gas company under its current ownership, the Company had a number of prior periodic rate cases when it was owned by Citizens Utilities. He contends that the transfer of ownership to UNS should not be used as a basis for imposing "excessive" rate case costs (Ex. S-27 at 42-43). Mr. Smith also testified that because the UNS rate case presents many issues that are similar to those considered in the Southwest Gas case (such as a proposed decoupling mechanism and revisions to the PGA), the rate case expense allowed in that case is a useful benchmark for the UNS case (*Id.*). On cross-examination, Mr. Smith also expressed a concern with the overall allocation methodology used by TEP for UNS expenses. He testified that the direct allocation methodology used by TEP may result in a double recovery, to the extent that the same personnel are used for different companies, because "it could potentially result in loading a disproportionate amount of their cost onto each utility to their rate case they are working on" (Tr. at 896-97). He conceded that the Commission should allow an appropriate level of rate case costs, but indicated that "this is a potential cost here that can get totally out of control if some limits aren't placed on it" (Tr. at 898).

We agree with Staff and RUCO that the Company's proposed rate case expense of $900,000 is excessive and should be reduced significantly. As both Staff and RUCO suggest, the recent Southwest Gas case presented many of the same issues that were raised in this case, and the Southwest Gas case is an appropriate measure of comparison for UNS. In response to the Company's claim that Southwest Gas employed a different method of allocating such costs, and was therefore not comparable to UNS, Staff witness Smith pointed out potential problems with the method used by TEP to allocate costs such as rate case expense. We believe that proposed rate case expense of $900,000 is excessive when compared with similar rate case expense allowances in a long line of cases before the Commission. Although Staff and RUCO present strong arguments in support of their recommendations, given that this is the first UNS Gas rate case since the acquisition of the Citizens assets, and that UNS was required to respond to a substantially higher number of data requests than was Southwest Gas, we allow rate case expense of $300,000, amortized over three years.

Customer Call Center Expenses

During the test year, on May 1, 2005, UNS changed its method of responding to customer calls by implementing a consolidated call center operated by TEP, with a level of costs allocated to UNS. RUCO witness Moore stated that prior to May 1, 2005, UNS Gas operated its call center separately, using 6 customer service representatives at a cost of $17,636 per month (RUCO Ex. 3 at 20). After consolidation of the call center, UNS began to incur allocated costs of $76,227 per month (*Id.*). The Company also subsequently closed walk-in customer service offices in Prescott, Cottonwood, Flagstaff, and Show Low, thereby requiring customers in those areas to use "payday loan"[7] stores if they want to pay their bills in person (Tr. at 418).

UNS witness Dallas Dukes stated that the consolidated call center provides a higher level of service to customers and indicated that the prior individualized system would have required a significant investment in new systems to respond to rapid growth in the Company's service area. Mr. Dukes cited a number of benefits of the consolidated operations, including the ability to handle increased call traffic, which has nearly doubled since the prior individual operations were in place; expanded service hours; a credit card payment option; call volume tracking ability; and one number availability for gas and electric customers in Mohave and Santa Cruz counties (Ex. A-13 at 29-30). In response to RUCO's claims that customer complaints have increased since the new call center was put in place, Mr. Dukes stated that the primary driver of the increased call volumes was higher gas costs that flowed through to customers. He reiterated that the former individual office format could not have handled the increased volume of calls and that the old system would have required increased staffing and investment to keep up with service demands (Ex. A-14 at 16).

RUCO witness Moore disagrees with the Company's contention that the consolidated call center provides increased customer service. He claims that in 2004, prior to the call center consolidation, 13 percent of the 178 total complaints against the Company related to customer service; in 2005, when the new call center was introduced, 22 percent of the 172 total complaints related to customer service; and in 2006, 17 percent of the 143 total complaints[8] related to customer service (RUCO Ex. 4 at 11; Tr. at 614-15). Based on this data, RUCO argues that UNS is providing worse customer service under the new call center format, despite a 432 percent increase in costs. Accordingly, RUCO recommends that the Company's customer service costs should be reduced to the level incurred prior to the introduction of the consolidated call center.

We do not believe that the record supports the disallowance sought by RUCO on this issue. RUCO's analysis is based on a simple comparison of complaint data and system costs, but does not

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[7] The payday loan store issue is discussed in detail below. UNS currently retains walk-in company offices in Nogales, Kingman, and Lake Havasu.

[8] Mr. Dukes claims that the Company's records reflect 120 UNS Gas complaints in 2005 and 149 complaints in 2006 (Ex. A-14 at 16).

consider the underlying reasons why consolidation to a modernized call center was necessary. The Company's witness cited a number of advantages associated with the new call center operations and pointed out that RUCO's proposal fails to account for the doubling of call volume since the new system was put in place and does not include recognition of the additional investment that would have been required to update the prior decentralized system of customer service. Although we believe that the consolidated call center costs should be allowed in the Company's expenses in this case, we have ongoing concerns regarding UNS's decision to close a number of local offices and farm out its customer service obligations to payday loan stores, as discussed below.

Miscellaneous "Unnecessary" Expenses

RUCO witness Rodney Moore presented testimony requesting that the Company's test year expenses should be reduced by $233,347 for expenses that were "questionable, inappropriate and/or unnecessary" (RUCO Ex. 3 at 22). Mr. Moore claims that his proposed adjustment is related to payments made to chambers of commerce and non-profit organizations and for donations; club memberships; gifts; awards; extravagant corporate events; advertising, and various meals, lodging and refreshments (*Id.*). He cites a sampling of the 1,995 questionable expenses, which include $1,200 for two people to play in a Flagstaff golf tournament, $5,750 for an employee appreciation dinner, $1,000 for Toys for Tots, $3,058 for the Flagstaff Chamber of Commerce, and $1,246 for a chartered air flight (*Id.* at 23).

In response to RUCO's claims, UNS witness Gary Smith testified that most of the expenses related to travel for "regulatory-mandated functions such as leak surveys, safety audits, and training"; that other expenses included "participation in the annual mandatory Commission Pipeline Safety audit and required operator qualification training, welder qualification training, and emergency response testing"; and that many of the remaining expenses are for "small tools that are necessary for maintaining the pipeline system" (Ex. A-16 at 5-6). UNS argues that Mr. Moore did not respond to Mr. Smith's explanation but, instead, attacked Mr. Dukes' suggestion that RUCO should limit its audit to material items because 90 percent of the challenged expenses are under $200 and 65 percent under $50 (Tr. at 636). The Company asserts that RUCO's demand for a specific explanation of why each claimed expense is reasonable is "profoundly unreasonable," (UNS Initial Brief at 25), because

RUCO did not consider the cost of preparing such a response and could have pursued alternate means of verification during discovery. However, in an attempt to appease RUCO, UNS witness Smith stated in his rejoinder testimony that the Company would agree to a disallowance of $27,968 (Ex. A-17 at 3).

This issue is eerily similar to the position taken by Southwest Gas in its last rate case, wherein its witness attempted to deflect the burden of proving the reasonableness of Southwest Gas's claimed expenses for a number of "small ticket" items including jeep tours, balloon rides, club memberships, charitable donations, sports events, barbecues, flowers, and various food and drinks expenses. In that case, the Southwest Gas witness agreed to exclude what she perceived to be clearly inappropriate miscellaneous expenses, but indicated that many of the expenses were too small for even the company to determine whether they should be included in cost of service. Southwest Gas's witness therefore concluded that RUCO had not presented sufficient evidence to support its proposed disallowance. Here, UNS makes an almost identical argument, claiming that because the costs individually are too small to track, RUCO's recommendation must fail. In the Southwest Gas Decision (Decision No. 68487 at 19-21), we rejected that argument, finding that Southwest Gas had not met its burden of proof. As we stated in Decision No. 68487, "[i]t is curious that Southwest Gas seeks to cast the burden of proving the unreasonableness of expenses on RUCO, especially once RUCO has provided some evidence that certain claimed expenses are inappropriate and which evidence, by the Company's own admission, should result in additional exclusions" (*Id.* at 21).

Consistent with the Southwest Gas Decision, we find that a portion of the claimed expenses in this "miscellaneous" category should be disallowed because UNS failed to meet its burden of proof as to their validity. Recognizing that many of the expenses appear to be legitimate expenses related to training, safety, and maintenance, however, we disallow half of RUCO's proposed disallowance ($233,347 x 50% = $116,674). While it may seem unfair for a utility company to be required to come forward with supporting evidence regarding the reasonableness of even small expenses, when the Company is seeking to place the burden of such expenses exclusively on the backs of its customers, it is required to prove that the expenses were reasonably necessary for the provision of service to those customers. If we were to adopt UNS's rationale regarding these relatively small, miscellaneous expenses, it would be akin to proclaiming the acceptability of the proverbial "death by 1,000 cuts."

Performance Enhancement Program

UNS allows its non-union employees to participate in its parent company's Performance Enhancement Program ("PEP"), which provides eligible employees compensation above their base pay for meeting financial targets (30 percent), cost containment goals (30 percent), and customer service goals (40 percent) (Ex. A-13 at 8-9). Company witness Dukes claims that the PEP is an integral part of its compensation package for employees and that UNS would be required to increase base salaries to attract and retain qualified employees if the program were eliminated (*Id.*).

Staff proposes to adjust the PEP expenses by 50 percent, based on Staff's claim that incentive compensation programs benefit both ratepayers and shareholders. Staff cites to the Southwest Gas Decision to support its position. In that case, the Commission adopted Staff's recommendation to disallow 50 percent of a similar program's costs, based on a finding that the Southwest Gas management incentive program benefited both customers and shareholders. Staff witness Ralph Smith stated that there is no relevant distinction between the UNS and Southwest Gas incentive programs and that the 50/50 sharing of costs is equally appropriate in this case (Ex. S-25 at 29).

RUCO proposes a complete disallowance of the PEP costs, based on its claim that it is not clear that the program is necessary to achieve the PEP's goals. RUCO witness Moore testified that during the test year (2005), no PEP payments were made because UniSource did not meet the program's financial goals. However, the UniSource Board of Directors authorized payment of a Special Recognition Award ("SRA") in 2005 to the employees eligible for the PEP. As a result, UNS is seeking in this proceeding to recover the average of the 2004 PEP payments and the 2005 SRA costs. Mr. Moore contends that the SRA is unique and does not meet the criteria of a typical and recurring test year expense for which rate recovery should be granted (RUCO Ex. 3 at 16-17). He also stated that 60 percent of the PEP payments are related to financial performance and cost containment, which are goals that primarily benefit shareholders. Finally, Mr. Moore asserts that because the PEP does not apply to 60 percent of its employees (*i.e.*, union employees), it is not clear that the program is necessary or will achieve the stated goals (*Id.*; RUCO Ex. 4 at 8).

We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program. As RUCO points out, the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders. However, 40 percent of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area. For the same reasons, we also adopt Staff's recommendation to disallow 50 percent of the Officer's Long-Term Incentive Program (Ex. S-25 at 26).

Although we believe, on balance, that the 50/50 sharing is reasonable, we share RUCO's concerns that the SRA offered to employees in 2005 may have the effect of undermining the very goals the PEP is intended to achieve (*i.e.*, providing an incentive for participating employees to improve performance and thereby benefit both the Company and its customers). As described by Mr. Moore, despite failing to meet the PEP goals, the UniSource Board of Directors decided nonetheless to provide the affected employees with a surrogate means of compensation. It appears that the SRA sends a signal to employees that they will be compensated regardless of performance, which places the entire premise of the PEP at issue. We expect the program to be scrutinized in the Company's next rate case to determine the appropriateness of providing incentive compensation above base salaries to employees.

<u>Supplemental Executive Retirement Plan</u>

UNS Gas allows select executives to participate in a Supplemental Executive Retirement Plan ("SERP"). The SERP provides to eligible executives retirement benefits in excess of the limits allowed under Internal Revenue Service ("IRS") regulations for salaries in excess of specified amounts. UNS contends that the SERP costs are reasonable and that neither Staff nor RUCO have shown that the Company's overall executive compensation costs are excessive or out of line with industry standards.

Staff and RUCO recommend disallowance of the SERP costs ($93,075), in accordance with the Commission's Decision in the Southwest Gas case (Decision No. 68487, at 18-19). In that case, we disallowed Southwest Gas's SERP costs, finding:

> [T]he provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. (*Id.* at 19).

We disagree with the Company's argument that disallowance of the SERP costs effectively allows the IRS to dictate what compensation costs should be recovered. As was clearly stated in the passage cited above, the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case,[9] and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

More disturbing than the Company's advocacy on the relative merits of the SERP is the statement in its initial brief that "[h]ad UNS Gas been notified that SERP costs would not be allowed, it could have restructured its executive compensation package to take that into account. It would not be fair to hold UNS Gas to this new, unexpected standard." (UNS Initial Brief at 28.) Implicit in the Company's argument is the concept that "if we don't recover fully what we believe are our reasonable costs in our preferred manner, we'll simply shift those costs to another account to disguise the costs and ultimately ensure recovery." The approach to rate recovery seemingly advocated by UNS can serve only to increase the cynicism often expressed by ratepayers regarding the reasonableness of a given utility company's proposed rates and, if allowed, would at its essence turn the ratemaking process into a veritable regulatory version of "Three-Card Monte." We trust that in

[9] *See also Arizona Public Service Co.*, Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were excluded in their entirety.

future rate applications, Staff and RUCO will explore thoroughly the merits of individual expenses sought by UNS, as well as other companies, to ensure that customers are paying rates that include only the costs necessary to provide quality service.

Fleet Fuel Expense

UNS witness Dukes proposed that the Company's fleet fuel expense be established based on an average gasoline cost of $2.48 per gallon (Ex. A-13 at 19). Mr. Dukes stated that the average fuel price used by UNS reflects the Company's actual costs and that lower cost recommendations made by Staff and RUCO should be rejected. He testified that it is not surprising that UNS would have slightly higher fuel costs than some other utilities because the UNS Gas service area is farther from large metropolitan areas like Phoenix and Tucson and covers a larger number of square miles given its more rural location (*Id.*). In response to a proposed disallowance made by Staff witness Ralph Smith, Mr. Dukes reduced the Company's request by $12,657 (pre-tax) (*Id.* at 23-24).

In his surrebuttal testimony, Staff witness Smith agreed with Mr. Dukes' proposed reduction to fleet fuel expense (Ex. S-27 at 39). Although Staff appears to have reconciled its recommendation with the Company on this issue, UNS's brief continues to advocate rejection of Staff's position (UNS Initial Brief at 29-30). We assume that the Company failed to notice Mr. Smith's surrebuttal testimony agreeing with Mr. Dukes' rebuttal testimony, and we believe that there is no remaining dispute between UNS and Staff.

RUCO agrees that it is appropriate for UNS to annualize its fuel expense to reflect additional employees included in its payroll annualization adjustment. However, RUCO witness Diaz Cortez stated that because gasoline prices were abnormally high in early 2006, the Company's calculation inflated the annualized level of fuel expenses (RUCO Ex. 5 at 14-15). Instead of the proposal to base fuel expenses on an average of $2.48, RUCO recommends using $2.43 per gallon as the average cost (*Id.* at Sched. MDC-3). In addition, RUCO claims that UNS understated the actual miles per gallon (10.28 mpg) achieved by the UNS fleet (*Id.* at 15). On cross-examination, Mr. Dukes admitted that the Company did not respond to the second part of RUCO's recommendation (*i.e.*, the UNS fleet miles per gallon) (Tr. at 241-42). Nor did UNS address the miles per gallon issue in its brief.

We find that the Company has adequately supported the use of $2.48 per gallon as the basis for determining its fleet fuel costs in this proceeding. However, as Ms. Diaz Cortez pointed out, UNS did not respond to the second part of the RUCO recommendation dealing with fleet miles per gallon. We will therefore adopt RUCO's proposal to use the actual 2005 fleet miles per gallon as set forth in Ms. Diaz Cortez's schedules, adjusted by the inclusion of the $2.48 per gallon gasoline price recommended by UNS and Staff.

Bad Debt Expense

In its initial brief, UNS states that although the Company and Staff are in agreement as to the appropriate level of bad debt expense, RUCO's proposal to disallow $100,000 is based on a mismatch and should be rejected (UNS Initial Brief at 29). Ms. Diaz Cortez agreed in her surrebuttal testimony that "the numerator and the denominator of the bad debt ratio would have to be adjusted to remove the NSP and Griffith Plant" (RUCO Ex. 6 at 13). It appears that UNS failed to recognize RUCO's surrebuttal testimony on this issue and, as a result, continues to advocate rejection of a position RUCO conceded before the commencement of the hearing. Since there is no remaining disputed issue, we adopt the Company's recommendation on this issue.

Postage Expense

UNS proposed inclusion in operating expenses of $529,380 for postage costs, based on a two-year average (2005 and 2006) and including acknowledgement of a postal increase that became effective May 14, 2007 (from $.39 to $.41) (Ex. A-13 at 19-21).

In his surrebuttal testimony, Staff witness Ralph Smith modified an earlier adjustment and agreed with UNS that the postage expense starting point of $445,171 is appropriate, which produces an annualized postage expense of $476,960 to reflect a January 8, 2006 postage increase as well as customer growth that occurred during the test year. In addition, Mr. Smith agreed that the May 14, 2007, increase should be recognized, resulting in an overall postage allowance of $503,356 (Ex. S-27, at 39-40). The difference of $26,024 between the UNS and Staff recommendations relates to the Company's proposal to reflect the impact of 2006 postage expense. Mr. Smith stated that customer growth should only be reflected through the 2005 test year because inclusion of customer growth in

2006, without considering the commensurate growth in revenues, would result in an inappropriate mismatch (*Id.*).

RUCO witness Rodney Moore proposed an adjustment comparable to that proposed by Staff (RUCO Ex. 4 at 9). Like that of Staff, RUCO's adjustment is based on the use of historic test year levels, annualized for increases in customer levels and adjusted for known and measurable postal rate increases. As reflected in its final schedules (Final Sched. RLM-9), RUCO's recommendation is for an allowance of $502,018.

It is not clear whether the UNS initial brief recognized the adjustments made by Staff and RUCO in their surrebuttal testimonies, because the UNS brief states that the Staff and RUCO positions should be rejected due to "several errors" (UNS Initial Brief at 30). As described above, both Staff and RUCO eventually agreed with all of the Company's arguments on this issue except one: whether customer growth beyond the test year should be recognized in establishing postage expense. UNS did not address in its reply brief the arguments made in the Staff and RUCO initial briefs, so it is possible the Company is now in agreement with the Staff and RUCO recommendations on this issue. We agree with Staff and RUCO that customer growth should be recognized only through the end of the test year because to do otherwise would result in a clear mismatch between expenses and revenues under the Company's proposal. Although the Staff and RUCO recommendations result in slightly different amounts ($1,338 difference), the reason for the difference is not clear. We therefore adopt Staff's postage expense recommendation of $503,356.

<u>Depreciation and Property Taxes for CWIP</u>

Staff made adjustments to remove the Company's proposed pro forma amounts for depreciation and property taxes related to the request to include CWIP or, alternatively, post-test-year plant (Ex. S-27 at 26). Given our denial of the CWIP and post-test year plant proposals, Staff's adjustments are adopted.

<u>Overtime Payroll Expense</u>

Staff witness Ralph Smith recommended an adjustment to reduce the Company's proposed test year overtime payroll expense by $123,010 (Ex. S-25 at 28). The adjustment relates to Staff's normalization of the overtime payroll expenses (*Id.*). In his Rebuttal testimony, UNS witness Dukes agreed with Staff's proposal, conceding that Staff's recommendation is more reflective of expected overtime levels (Ex. A-13 at 17). Staff's recommendation is adopted.

Payroll Tax Expense

Staff witness Ralph Smith proposed a reduction to the Company's pro forma payroll tax expense by $9,348 to reflect Staff's adjustments to overtime payroll and incentive compensation expenses (Ex. S-27 at 34). Consistent with Staff's recommendations on the overtime payroll and incentive compensation issues, Staff's payroll tax expense adjustment is adopted accordingly.

Property Tax Expense

UNS proposed the use of a property tax rate of 24.5 percent (Ex. A-13, Attach. DJD-1). Both Staff and RUCO recommend setting allowable expenses for property tax based on a rate of 24.0 percent. Staff witness Ralph Smith testified that Staff's recommendation is based on the known and measurable assessment for 2007, pursuant to legislation passed by the Arizona State Legislature that reduces property tax assessments from a rate of 25 percent in 2005 by .5 percent in each successive year until a rate of 20 percent is achieved in 2015 (Ex. S-27 at 35-36). Mr. Smith stated that the Company's proposal fails to recognize the impact of the known tax change. He also indicated that Staff's recommendation is consistent with the recent Southwest Gas rate case (which had a test year ending August 31, 2004), wherein Southwest Gas, Staff, and RUCO agreed that a 24.5 percent assessment for the 2006 rate was appropriate for the calculation of property tax expense (*Id.*). RUCO witness Rodney Moore also proposed use of a 24.0 percent assessment rate for UNS in this case, based on the same rationale described by Mr. Smith (RUCO Ex. 4 at 14).

We agree with Staff and RUCO that the property tax expense allowance in this case should be based on the known and measurable assessment rate currently in effect. The rate for 2007 is currently 24.0 percent, and the rate will continue to decline in subsequent years while the rates established in this case are in effect. The Staff and RUCO recommendations are therefore adopted.

Membership and Industry Association Dues

UNS initially included $41,854 for dues paid to the American Gas Association ("AGA"). In his direct testimony, RUCO witness Moore recommended a partial disallowance of $1,523 of the

AGA dues based on an AGA/NARUC[10] Oversight Committee Report indicating that 1.54 percent of AGA dues are used for marketing and that 2.10 percent of dues are allocated for lobbying activities (RUCO Ex. 3 at 26-29). In his Rebuttal testimony, UNS witness Dukes agreed with Mr. Moore's proposed adjustment and revised the Company's proposed expenses in accordance with RUCO's recommendation (Ex. A-13, at 18-19).

Staff witness Ralph Smith recommended a larger percentage disallowance of the AGA dues and also proposed eliminating dues paid by the Company to a number of other organizations (primarily for dues to a number of local Chambers of Commerce within the UNS service area) (Ex. S-27 at 37-39; Sched. C-14). Mr. Smith stated that Staff's more aggressive disallowance proposal is based on language in the Southwest Gas Order, (Decision No. 68487, at 14), which admonished Southwest Gas in its next rate case to "provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its Arizona Ratepayers." Mr. Smith acknowledged that the Southwest Gas Order disallowed only the marketing and lobbying portions of the AGA dues (3.64 percent), consistent with RUCO's recommendation in this proceeding. However, he believes UNS should have been on notice to provide additional details regarding AGA activities, which the Company failed to supply. Mr. Smith based his 40 percent disallowance on 1999 and 2000 NARUC audit reports of AGA expenditures (which appear to indicate that approximately 40 percent of AGA dues are used for marketing and lobbying efforts) and on a decision issued by the Florida Public Service Commission disallowing 40 percent of AGA dues from expenses (Ex. S-25 at 34-37, Sched. RCS-3; Ex. S-27 at 37-39).

Mr. Smith raises a valid point regarding the nature of AGA dues and whether a higher percentage of such dues should be disallowed as related to activities that are not necessary for the provision of service to UNS customers. However, we believe it is reasonable, in this case, to allow $40,331 ($41,854 - $1,523), in accordance with RUCO's recommendation. As we indicated in the Southwest Gas Order, however, we expect UNS in its next rate case to provide more detailed support

[10] National Association of Regulatory Commissioners

for allowance of AGA dues and how the AGA's activities benefit the Company's customers aside from marketing and lobbying efforts.

With respect to Mr. Smith's proposal to disallow a number of smaller dues to Chambers of Commerce and similar organizations, we believe these types of expenses are encompassed within RUCO's recommendation regarding so-called "unnecessary" expenses, which are addressed in a prior section of this Order. Given that we disallowed 50 percent of those expenses, it is likely that an additional disallowance under Staff's recommendation would represent a double counting of the types of expenses identified by RUCO. We therefore decline to adopt Staff's recommendation on this issue.

Interest Synchronization

There does not appear to be any dispute that an interest synchronization adjustment is necessary to coordinate the income tax calculation with rate base and cost of capital. As set forth in Staff witness Ralph Smith's testimony, this adjustment decreases income tax expense and increases the Company's achieved operating income by a similar amount (Ex. S-27, Attach. RCS-2S, Sched. C-17).

CARES Related Amortization

Staff recommended that UNS cease deferral of costs related to the Customer Assistance Residential Energy Support ("CARES") program upon approval of the new rates established in this case. According to Staff witness Ralph Smith, Staff has recognized CARES program discounts in Staff's proposed rate design, and Staff recognizes UNS has accumulated some deferred costs related to the program (Ex. S-27 at 44). Based on Staff witness McNeely-Kirwan's recommendation regarding the ratemaking treatment for the accumulated deferred CARES costs, Mr. Smith reduced operating expenses by $441,511 (*Id.*, Sched. C-20). Given our adoption of staff's recommendation regarding the CARES program (see discussion below), Staff's proposed adjustment to operating income is appropriate.

Nonrecurring Severance Payment

Staff witness Ralph Smith initially proposed an adjustment to remove a nonrecurring severance payment for an employee who was dismissed in 2004, but whose severance payment was made in 2005 (Ex. S-25 at 27-28). UNS witness Dukes opposed Staff's recommendation, stating in his rebuttal testimony that because there was never an offsetting expense for this payment posted to the Company's books in 2005, payroll expense was understated by approximately $52,000 (Ex. A-13 at 15). In his surrebuttal testimony, Mr. Smith stated that Staff's prior adjustment was unnecessary because the item "was effectively adjusted to zero in the UNS Gas filing" (Ex. S-27 at 33).

In its Initial Brief, Staff contends that it disagrees with the attempt by Mr. Dukes "to revise its filing to add this nonrecurring severance expense back twice" (Staff Initial Brief at 15). UNS did not address this issue in either of its Briefs, but it appears from reading Mr. Smith's testimony that the issue was resolved prior to the hearing, considering Mr. Smith's statement that the prior Staff adjustment was unnecessary.

<u>Nonrecurring Union Training</u>

RUCO witness Moore recommended disallowance of $2,584 related to M.A.R.C. (Union) Training that, according to Mr. Moore, UNS had described as "a one-time only instructional session to acquaint Company personnel with working in a unionized environment" (RUCO Ex. 4 at 16). Mr. Moore claims that the expense is nonrecurring and should therefore be disallowed (*Id.*).

UNS witness Gary Smith stated that while the M.A.R.C. training was a one-time event, training is an ongoing activity that is required to comply with regulatory mandates. He claims that, since the end of the test year, another mandatory training program has been established for gas distribution companies to provide training to both the public and employees (Ex. A-17, at 4). The Company therefore requests that RUCO's recommendation be rejected. On cross-examination, Mr. Smith admitted that the M.A.R.C. training was a one-time event and that RUCO had not proposed to disallow any other training expenses incurred by the Company (Tr. at 416-17).

We agree with RUCO that the specific expense item identified by Mr. Moore is related to a one-time training cost that will not occur in the future. No other training costs are recommended for disallowance, and although the Company may face increasing training costs in the future, those costs will be addressed in a future rate case where all relevant test year revenues and expenses will be evaluated for inclusion in rates. We therefore adopt RUCO's recommendation on this issue.

New Depreciation Rates

Staff witness Ralph Smith indicated that Staff is in agreement with the Company's proposed new depreciation rates (Ex. S-25 at 63). However, Mr. Smith recommended that each of the new depreciation rates proposed by UNS should be clearly broken out by a service life and a net salvage rate. He indicated that this would allow the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates to be tracked and accounted for by plant account (*Id.*). There does not appear to be a dispute regarding the new depreciation rates to be employed by UNS. Further, the Company did not oppose Mr. Smith's suggestions for separating the depreciation rates for service life and net salvage. Staff's recommendation is therefore adopted.

Net Operating Income

Consistent with the foregoing discussion, we will allow adjusted test year operating expenses of $37,652,416, which based on test year revenues of $47,273,923, results in test year adjusted operating income of $9,621,507, a 5.30 percent rate of return on FVRB.

COST OF CAPITAL

UNS Gas recommends that the Commission determine the Company's cost of common equity to be 11.0 percent, with an overall weighted cost of capital recommendation of 8.80 percent. Staff recommends a cost of common equity of 10.0 percent, with an overall weighted cost of capital determination of 8.12 percent. RUCO proposes adoption of a cost of common equity of 9.84 percent, with an overall weighted cost of capital of 8.22 percent (RUCO Ex. 8 at 2).

Capital Structure

At the end of the test year, UNS had a capital structure consisting of 55.33 percent long-term debt and 44.67 percent equity (Ex. A-27 at 8). UNS proposes using a hypothetical capital structure of 50 percent debt and 50 percent equity because it is striving to increase its equity ratio to 50 percent and believes that the rates set in this case should reflect the capital structure that would exist when the rates set in this case are in effect (Tr. 964).

According to UNS witness Kentton Grant, "it is reasonable for the Company to target a higher common equity ratio due to the Company's small size, large capital spending needs and limited borrowing capacity" (Ex. A-27 at 8-9). He claims that UNS forecasts achieving a 50 percent equity ratio by the end of 2008 (*Id.*). In support of the Company's improving equity ratio, Mr. Grant points out that UNS Gas has improved its equity ratio from 33 percent in August of 2003 to 45 percent at the end of 2005. He stated that this improvement has been achieved by UNS Gas's retaining 100 percent of its annual earnings and through additional equity investments from its parent, UniSource Energy. Mr. Grant testified that despite the absence of any dividends being paid by UNS to UniSource over the past several years, UniSource has invested an additional $16 million of equity capital in UNS Gas (*Id.*).

UNS cites to the most recent Southwest Gas Order to support its request for employing a hypothetical capital structure (Decision No. 68487, at 23-25). In that case, the Commission agreed with Staff's request to use a hypothetical capital structure of 40 percent equity, but rejected Southwest Gas' request to use 42 percent equity in the capital structure. During the test year in that case, Southwest Gas had an average actual capital structure of 34.5 percent equity, 5.3 percent preferred stock, and 60.2 percent long-term debt (*Id.* at 23). In this case, Mr. Grant indicated that using the Company's recommended hypothetical capital structure would help alleviate the current weakness in earnings and cash flow in order to offset the negative credit impact of weak cash flows (*Id.* at 10).

RUCO supports the Company's request to use a 50/50 hypothetical capital structure to establish UNS's cost of capital in this proceeding. RUCO witness William Rigsby stated that UNS's capital structure is more heavily weighted with debt than the average of the companies used in his comparable company analysis. He also indicated that the other local gas distribution companies ("LDCs") in his sample group had an average of 48 percent debt and 52 percent equity, compared to UNS at approximately 55 percent and 45 percent, respectively (RUCO Ex. 7 at 43). As a result, Mr. Rigsby suggested, the LDCs in his proxy group would have a lower level of financial risk compared to UNS. As discussed below, Mr. Rigsby did not make an adjustment to his cost of equity analysis to account for a higher level of financial risk but, instead, testified that his hypothetical capital structure recommendation gives recognition to this higher risk (*Id.* at 44).

Although UNS and RUCO are in agreement on the employment of a 50/50 capital structure, Staff contends that a hypothetical capital structure is not appropriate in this case. Staff witness David

Parcell testified that both UNS Gas and UNS Electric currently have higher equity ratios than either TEP or UniSource Energy, and the actual UNS equity ratio is comparable to those of other electric and combination gas and electric utilities (Ex. S-36 at 19-20). Mr. Parcell stated that using a hypothetical capital structure would have the effect of "increasing the actual return on equity to a level exceeding that intentionally approved by the Commission" (*Id.* at 20). According to Mr. Parcell, adopting the Company's proposed 50/50 capital structure would have the net effect of increasing the actual authorized return on equity by 50 basis points, or 0.50 percent (*Id.* at 21).

With respect to the Commission's use of hypothetical capital structures in prior cases, Staff argues that the circumstances are different for UNS. Staff cites to a recent Arizona-American Water Company (Mohave) case in which the Commission adopted a hypothetical capital structure of 40 percent equity and 60 percent debt, although the company's actual structure consisted of 37.2 percent equity and 62.8 percent debt (Decision No. 69440, at 13). Staff asserts that the Commission's Decision in that case was based on its concern that Arizona-American was more highly leveraged than its comparable companies. According to Staff, UNS's capital structure is in line with other comparable companies, so no similar concern exists. Staff contends that the same reasoning holds true with respect to Southwest Gas, which had a highly leveraged capital structure, with more than 60 percent long-term debt during the test year. Staff argues that a hypothetical capital structure should be employed only where a company's actual capital structure is out of line with comparable companies, or where the actual capital structure contains higher cost equity capital, which would be unduly expensive to ratepayers.

Although we understand and appreciate Staff's concerns, we believe the hypothetical capital structure recommendation recommended by UNS and RUCO is reasonable in this case. We believe the Company's efforts to improve its equity ratio over the past several years, through retained earnings and additional equity investment by its parent, should be recognized and encouraged. As indicated by UNS witness Grant, the Company's equity ratio has improved steadily since 2003, and UNS anticipates achieving a 50 percent equity ratio by the end of 2008.

While we recognize that, from a capital structure standpoint, UNS is situated differently from Southwest Gas, we believe it is necessary to express the same concern that was indicated in the

Southwest Gas case regarding ongoing use of a hypothetical capital structure for establishing a company's cost of capital and the rates that flow from that determination. As stated therein, "[a]t some point, we must send Southwest Gas a signal that it must improve its capital structure up to the hypothetical level that has been employed for many years or it must live with the results of its actual capital structure" (Decision No. 68487, at 25). Given the historical and anticipated progress of UNS in improving its equity ratio, we believe it is likely that use of the Company's actual capital structure in future cases would produce a reasonable cost of capital result. In this case, however, we find that the record supports use of the Company's 50/50 capital structure.

Cost of Debt

All parties in the case agreed that the Company's cost of debt was 6.60 percent during the test year. Since there is no dispute regarding this issue, we will adopt a cost of debt of 6.60 percent for purposes of establishing UNS Gas's weighted cost of capital in this proceeding.

Cost of Common Equity

Determining a company's cost of common equity for purposes of setting its overall cost of capital requires an estimate based on a number of factors. There is no fool-proof methodology for making this determination, and the expert witnesses rely on various analyses to support their respective recommendations.

UNS Gas

UNS witness Kentton Grant based his common equity cost recommendation of 11.0 percent on the results of his common equity models, namely the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM"). Mr. Grant also examined the risk profile of UNS Gas relative to a comparable company group to determine a point in the range produced by those models. The estimated cost of equity produced by this analysis was then compared to the allowed returns for other LDCs in the United States to confirm the reasonableness of the Company's estimate. As a final matter, Mr. Grant examined the financial impact of the recommended return on equity ("ROE") and the overall rate request to assess the Company's ability to attract capital on reasonable terms (Ex. A-27 at 10-11).

Mr. Grant claims that it was appropriate to use a comparable group of LDCs in his analysis because the cost of equity capital for UNS Gas's parent company, UniSource Energy, which is heavily weighted toward the electric industry, may not be representative of the cost of equity capital for UNS Gas. Mr. Grant's comparable group was based on all 16 LDCs evaluated by *Value Line Investment Survey* ("*Value Line*"), from which 11 companies were selected based on several criteria that Mr. Grant believes make them comparable to UNS Gas (*Id.* at 12).

Mr. Grant explained that the DCF methodology is based on the theory that the price of a share of stock is equal to the present value of all future dividends. As described by Mr. Grant, the constant growth form of the DCF model recognizes that the return to shareholders consists of both dividend yield and growth. He stated that the constant growth form of the model should not be used for companies with near-term growth rates that are significantly higher or lower than their long-term growth potential. For such companies, Mr. Grant claims that a multi-stage DCF model should be used to incorporate the various growth rates that are expected over time (*Id.* at 13).

According to Mr. Grant, an annual long-term growth rate of 6 percent represents a reasonable estimate of investor expectations for earnings and dividends, which he claims is consistent with the 6.1 percent median growth rate in earnings per share ("EPS") for his comparable company group published by *Value Line*, as well as a five-year estimate of EPS growth reported by *Thomson Financial* of 5.6 percent for the gas utility industry and 6.4 percent for the broader utilities sector (*Id.* at 16). Based on his application of a multi-stage DCF model, the estimated cost of equity for the sample companies produced a range of 9.1 percent to 10.5 percent, with a median value of 9.9 percent (*Id.* at 18).

Mr. Grant stated that use of the CAPM is premised on the concept that capital markets are highly efficient and that investors attempt to optimize their risk/return profiles through diversification. He indicated that the CAPM assumes that risk is comprised of systematic risk (which is unavoidable) and unsystematic risk (which is company-specific and can theoretically be eliminated through portfolio diversification). As a result, Mr. Grant explained that the CAPM is based on the theory that investors should be compensated only for systematic risk (*Id.*). Applying the CAPM produced a result of 9.9 percent to 11.0 percent. Based on his comparison of the DCF and CAPM results, Mr. Grant selected a range of 9.5 percent to 11.0 percent as the Company's estimate of the cost of equity for the comparable company group (*Id.* at 20).

The next step in the Company's analysis was to determine the appropriate return on equity ("ROE") in this proceeding for UNS Gas, based on a comparison of the "risk profiles" of UNS and the comparable companies. Mr. Grant asserts that an equity investment in UNS Gas is "decidedly riskier" than an equity investment in the comparable companies due to several factors, including UNS Gas's smaller size, a higher growth rate in net plant investment, the lack of a decoupling mechanism, and lower credit ratings for UNS Gas than for most of the comparable companies. Based on these relative risk factors, Mr. Grant proposes that the ROE for UNS Gas be set at the top of the range for comparable companies and that the Commission award a ROE of 11.0 percent in this proceeding (*Id.* at 21-23).

UNS is critical of the ROE recommendations of both Staff and RUCO based on the Company's claim that Staff and RUCO's use of a geometric means in calculating the market risk premium of their CAPM models is contrary to sound financial theories. UNS argues that an arithmetic means is supported by academics and financial professionals. The Company also contends that RUCO's analysis placed too much emphasis on near-term analyst growth forecasts, a methodology that UNS contends has been rejected by the Commission in two recent cases. UNS is also critical of RUCO's use of a single-stage DCF model, which assumes that company growth rates will continue in perpetuity, and of RUCO's over-reliance on analyst forecasts.

Finally, UNS criticizes Staff's and RUCO's ROE recommendations based on the Company's claim that the results fail a basic test of reasonableness. UNS contends that Staff's (10.0 percent ROE) and RUCO's (9.64 percent ROE)[11] recommendations are below ROEs approved by other state commissions and that UNS Gas bears much greater risk than comparable LDCs due to the factors cited in Mr. Grant's testimony (UNS Initial Brief at 37-38). Based on the Company's higher risk assertion, it claims, it must be awarded a higher ROE commensurate with that risk.

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[11] UNS apparently failed to observe that RUCO made an upward adjustment in its ROE recommendation (to 9.84 percent) through Mr. Rigsby's surrebuttal testimony filed on April 4, 2007 (RUCO Ex. 8, at 2).

RUCO

RUCO witness William Rigsby proposes adoption of a ROE of 9.84 percent based on his analysis using DCF and CAPM methodologies (RUCO Ex. 8 at 2). As noted above, Mr. Rigsby employed a single-stage DCF analysis, as opposed to the multi-stage version used by UNS. RUCO contends that Mr. Rigsby's DCF analysis is appropriate because it takes into consideration both short-term and long-term growth projections that are specific to the LDCs used in Mr. Rigsby's proxy group (RUCO Ex. 7 at 46).

RUCO is critical of Company witness Grant's DCF model, which RUCO claims assumes a long-term growth rate for LDCs that would be comparable to an inflation-adjusted growth rate for all goods and services produced by labor and property in the United States in perpetuity. According to Mr. Rigsby, a valid argument could be made that regulated utility company growth rates may not be comparable to national Gross Domestic Product ("GDP") growth rates, and therefore, the multi-stage DCF advocated by UNS is inappropriate (*Id.*). Mr. Rigsby also stated that the multi-stage DCF used by the FERC requires more weight to be given to short-term growth expectations rather than inflation-adjusted estimates of future GDP growth (RUCO Ex. 8 at 9). Mr. Rigsby pointed out that if the Company's DCF inputs (excluding Cascade Natural Gas – which RUCO claims has a stock price that is affected by a merger proposal) were applied to RUCO's single-stage DCF model, the resulting mean average would be significantly less than even Mr. Rigsby's DCF estimate (RUCO Ex. 7 at 47).

With respect to its CAPM analysis, RUCO asserts that the use of both geometric and arithmetic means of historical returns is more reasonable than the Company's exclusive reliance on arithmetic returns (*Id.* at 28). Similar to the arguments made by Staff (see below), RUCO contends that it is appropriate to use both means in the CAPM analysis, because investors have access to both forms of information regarding historical returns. Mr. Rigsby added that he believes the geometric mean provides "a truer picture of the effects of compounding on the value of an investment when return variability exists" (RUCO Ex. 8 at 12).

RUCO also disagrees with UNS regarding the effect that customer growth should have on the Company's return on equity. Contrary to the Company's claim that high growth presents additional risk that must be reflected through a higher authorized return, RUCO argues that high growth in

Arizona is a positive factor that should be a selling point to UniSource investors. RUCO cites to UniSource's 2005 Annual Report, in which UniSource's Chairman touted the company's customer growth rate in excess of 4 percent as a positive factor (*Id.* at Attach. E). RUCO also notes that a Standard & Poors report attached to Mr. Grant's testimony indicates that high customer growth could produce greater profitability or rate stability for an LDC (Ex. A-28, Attach. KCG-12). RUCO claims that it has not ignored the demand for capital that customer growth places on UNS operations, as reflected by RUCO's support for use of the Company's proposed 50/50 hypothetical capital structure.

Staff

Staff witness David Parcell presented Staff's ROE recommendation in this case. In developing his recommendation, Mr. Parcell utilized DCF, CAPM, and Comparable Earnings Method ("CEM") analyses. He indicated that because UNS Gas is not publicly traded, it is not possible to directly apply cost of equity models. In his analysis, Mr. Parcell employed 2 comparable groups of companies as a proxy for UNS Gas (Ex. S-36, at 21-23). The first sample group was comprised of a group of nine combination gas and electric companies and the second group consisted of the same 11 natural gas companies used by the Company's witness.

Mr. Parcell's DCF analysis produced a range of 9.25 percent to 10.5 percent for the proxy groups' cost of equity. His CAPM model produced a cost of equity range of 9.5 percent to 10.25 percent for the sample groups (*Id.* at 25-28). Mr. Parcell also utilized a CEM analysis, which he described as a method designed to measure the returns expected to be earned on the original cost book value of similar risk companies. According to Mr. Parcell, his CEM analysis was based on market data using market-to-book ratios, and is therefore a market test that should not be subject to criticisms leveled at other analyses that are based on past earned returns. He also claims that the CEM uses prospective returns and is therefore not backward-looking (*Id.* at 31-32). Using the CEM, Mr. Parcell concluded that the cost of equity for the proxy companies is "no more than 10 percent" (*Id.* at 33).

Based on the results of the three methodologies, Mr. Parcell found an overall range of 9.25 percent to 10.5 percent ROE for the proxy companies. He indicated that the range of mid-points for the three methodologies is 9.88 percent to 10.0 percent. Mr. Parcell concluded that the appropriate cost of equity rate for UNS Gas is in the range of 9.5 percent to 10.5 percent. He recommended that the Commission adopt the mid-point of the range (10.0 percent) as the ROE in this case.

With respect to the arguments raised by the Company, Staff asserts that UNS failed to give any weight to its own DCF analysis and relied exclusively on its excessive CAPM results. Staff contends that UNS's CAPM analysis is flawed because it uses a risk-free rate of 5.3 percent, which Staff claims is outdated and exceeds the current level of U.S. Treasury Bond yields, and the Company used an inappropriate equity risk premium of 7.1 percent, which is based exclusively on the arithmetic means of common stock and bond returns from 1926 to 2005.

In response to the Company's criticism of Staff's use of geometric means in its analysis, Staff cites to Mr. Parcell's surrebuttal testimony, wherein he indicated that investors have access to both arithmetic and geometric returns in making investment decisions and that many mutual fund investors rely on geometric returns in evaluating historic and prospective returns of funds (Ex. S-37 at 3). Staff also points to Mr. Parcell's testimony indicating that *Value Line* reports show historic returns based on a geometric or compound growth rate basis (*Id.*).

<u>Conclusion on Cost of Equity</u>

Having considered the testimony, exhibits, and arguments, we believe that Staff's recommended cost of equity capital produces a reasonable result and should be adopted. Staff witness Parcell's proposed 10.0 percent cost of equity provides a reasonable balance between the Company's attempt to place the ROE at the very top of the range produced by the Company's analysis and the results achieved through the methodologies employed by Staff and RUCO.

As noted above, Mr. Parcell's DCF analysis produced a range of 9.25 percent to 10.5 percent for the proxy groups' cost of equity, his CAPM model produced a cost of equity range of 9.5 percent to 10.25 percent for the sample groups, and his CEM analysis produced a result for the proxy companies of no more than 10 percent. Based on his conclusion that UNS Gas has an estimated ROE of 9.5 to 10.5 percent, Mr. Parcell recommended awarding the Company a ROE at the mid-point of the range, or 10.0 percent.

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. Although there continues to be disagreement regarding the risk effect from high customer growth, we believe that high growth has the potential for providing benefits through increased revenues. In any event, our adoption of the hypothetical capital structure proposed by UNS and RUCO gives recognition to the short-term capital needs associated with growth.

Accordingly, we adopt Staff's recommended 10.0 percent ROE in this proceeding for UNS Gas, which results in an overall weighted average cost of capital of 8.30 percent.

	Percentage	Cost	Avg.Weighted Cost
Common Equity	50.0%	10.0%	5.00%
Total Debt	50.0%	6.60%	3.30%
			8.30%

Chaparral City Decision and Fair Value Rate Base

In its application, UNS proposed that the weighted average cost of capital ("WACC") should be applied to its original cost rate base to determine the required operating income in this case (Ex. A-10, Sched. A-1). However, in the rebuttal testimony submitted by UNS witness Pignatelli, the Company suddenly made the claim that its WACC should be applied to FVRB. UNS claims that its change of position was based on its understanding of a recent Memorandum Decision issued by the Arizona Court of Appeals in *Chaparral City Water Co. v. Ariz. Corp. Comm'n*, 1 CA-CC 05-0002 (Ariz. App. Feb. 13, 2007) ("*Chaparral City*"). According to Mr. Pignatelli's rebuttal testimony, UNS is not requesting that its change of position result in a revenue requirement finding that would exceed the amount originally requested by the Company (Ex. A-2 at 8).

UNS argues that in the Chaparral City case before the Commission, the Commission adopted Staff's recommendation to calculate the revenue requirement by multiplying OCRB by the cost of capital (Decision No. 68179, at 26-28). UNS claims that only after this exercise was completed did Staff calculate the FVRB for Chaparral City, which resulted in what UNS contends is a "backing-in" approach because the FVRB calculation is a meaningless exercise that flows from the OCRB and cost of capital equation. UNS witness Grant asserted that the approach advocated by Staff in this case is mathematically equivalent to the methodology used in the Chaparral City case and rejected by the Court of Appeals (Ex. A-29, at 13).

In support of its argument, UNS cites to Article 15, §14 of the Arizona Constitution, which states in part that "[t]he Corporation Commission shall, to aid it in the proper discharge of its duties, ascertain the fair value of the property within the State of every public service corporation doing business therein…" UNS cites several cases[12] in support of its argument that the Commission is required to determine a company's fair value rate base and use that rate base in establishing the company's rates. UNS concedes that its proposal to apply the WACC to FVRB is not the only possible approach to setting rates, but suggests that it is the only approach presented in this case that complies with the Arizona Constitution. The Company claims that other permissible methods may be developed in future cases but, that for now, the UNS methodology is the only available choice for the Commission to apply.

RUCO argues in its brief that application of the WACC to FVRB, rather than to the OCRB initially requested by UNS, could be significant if the Commission adopts any of the positions advocated by Staff or RUCO regarding the Company's rate request. RUCO contends that the Company's change of position was untimely and, for that reason alone, should be rejected. Ms. Diaz Cortez stated in her surrebuttal testimony that, had UNS made its request to apply WACC to FVRB in its original application, RUCO's analysis of the cost of capital would have been entirely different and would likely have produced different results. She indicated that RUCO did not have sufficient time to conduct discovery regarding the change of position between the filing of the Company's rebuttal testimony and the filing of RUCO's surrebuttal testimony, some 13 business days later (RUCO Ex. 6, at 4-5). RUCO also argues that because *Chaparral City* was a Memorandum Decision, it cannot be regarded as precedent or cited. RUCO further asserts, citing Paragraph 17 of the Decision, that the Court confirmed the Commission is not required to apply a WACC to FVRB.

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[12] *U.S. West Communications, Inc. v. Ariz. Corp. Comm'n*, 201 Ariz. 242, 246, 34 P.3d 351, 355 (2001); *Simms v. Round Valley Light & Power Co.*, 80 Ariz. 145, 151, 294 P.2d 378, 382 (1956); *Scates v. Ariz. Corp. Comm'n*, 118 Ariz. 531, 533-534, 578 P.2d 612, 614-615 (App. 1979); *Phelps Dodge Corp. v. Arizona Electric Power Co-op*, 207 Ariz. 95, 83 P.3d 573, 586 (App. 2004).

Staff argues that the Company's reliance on the unpublished *Chaparral City* decision is misplaced. Staff points out that the Court of Appeals specifically indicated that the Commission was not required to apply the WACC to FVRB in order to set rates. Staff contends that it is still reviewing the Court's remand order, but the methodology proposed by Mr. Grant would result in an unreasonable and excessive return on equity for UNS. Staff cites to Mr. Parcell's testimony addressing the Company's amended proposal. Mr. Parcell testified that, under UNS's proposal, the link between rate base and capital structure would be broken because the "excess" of fair value rate base over original cost rate base is not financed with investor-supplied funds, and therefore the cost of capital cannot be applied to the fair value rate base because there is no financial link between the two concepts (Ex. S-37 at 8-9). Mr. Parcell's proposed solution is to recognize that the difference between FVRB and OCRB is not financed with investor funds by attributing no cost to the excess between the two. He stated that this recommendation would provide for a return being earned on all investor-supplied funds, which is consistent with sound financial and regulatory standards (*Id.*).

In support of its proposal, Staff cites to decisions rendered in several other states which recognized the problem of applying the cost of capital to fair value rate base[13]. Staff contends that, consistent with the problems identified by Mr. Parcell, application of modern cost of capital models, such as DCF and CAPM, directly to FVRB would create redundancies and double counting. Staff cites the case of *Railroad Commission of Texas v. Entex, Inc.*, 599 S.W.2d 292 (Tx. 1980), in which the Texas Supreme Court discussed the so-called "backing-in" method of determining fair value rate of return. In that case, the court stated that "[i]n a fair value jurisdiction the rate of return multiplied by the rate base usually resulted in a higher return to the book common equity than in an original cost jurisdiction because of the inclusion of the reproduction cost new factor." (*Id.* at 298). In rejecting the "backing-in" argument presented by the utility company, the Texas Supreme Court observed that, in fair value jurisdictions, the return to book common equity is used as a performance indicator by investors, and that fact could not be ignored by blindly applying a rate of return to fair value rate base

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[13] In *Re Harbour Water C*orporation, 2001 WL 170550 (Indiana Utility Regulatory Commission); *Gary-Hobart Water Corp. v. Indiana Utility Regulatory Comm'n*, 591 N.E.2d 649, 653 (Ind. App. 1992); *State of North Carolina ex rel. Utilities Commission et al. v. Duke Power Co.*, 285 N.C. 377, 397, 206 S.E.2d 269, 294 (N.C. 1974); *State of North Carolina ex rel. Utilities Commission et al. v. Virginia Electric and Power*, 285 N.C. 398, 206 S.E.2d 283 (N.C. 1974).

without recognizing the consequences of such a rate of return on the elements of the company's capital structure. The court also stated:

> [T]he fairness of the rate base or the rate of return can be measured by the cash requirements of the utility. All are interdependent and ultimately need to be reconciled....*a return to book common equity which is out of proportion...cannot be ignored since it is more than necessary to attract capital, and therefore, unfair to the ratepayer.* (*Id.* at 299, emphasis added).

Staff argues that, as recognized in the *Entex* case quoted above, the question that must properly be addressed is whether investors expect an additional return in excess of the return resulting from application of the financial models used for calculating the appropriate authorized return. Staff contends that there is no evidence that investors expect such an excess return and that the record supports an opposite conclusion. Staff asserts that the difference between applying the return to OCRB and FVRB would be, in effect, a windfall on unrealized paper profits. Staff claims that Mr. Parcell's proposal to assign no cost to the "excess" between OCRB and FVRB is logical and consistent with investor expectations. Staff argues that, to the extent that investors may expect a return on the so-called paper profits, such a return is already incorporated into the cost of capital models employed by the experts in this case. Staff states that, as an example, forecasted earnings per share and dividends per share would be higher if investors expect a utility's assets to grow in value, and historical EPS and DPS would also incorporate growth between a utility's prior and current rate cases. Staff indicates that it will continue to evaluate how to calculate a fair value rate of return, in accordance with the *Chaparral City* decision, and it is possible that a different mathematical adjustment may be developed in the future. Staff argues that UNS did not present any evidence as to how to adjust the cost of capital models in order to determine an appropriate fair value rate of return and that adopting the Company's request would create excessive returns for UNS.

We find the Company's eleventh-hour proposal to substantially amend its application on this issue to be inappropriate, because it is prejudicial to the other parties. Having prepared discovery based on the original proposal, Staff and RUCO were left with insufficient time to conduct discovery regarding the Company's amended proposal and were therefore prejudiced by having insufficient time to adequately prepare for hearing in this matter. If UNS wished to amend its application regarding a substantial change in the underlying theory of ratemaking upon which it decided to rely, it should have withdrawn its original application and started the entire process over. Based on the procedural deficiencies of the Company's amendment to its application and the prejudicial impact on the opposing parties, its proposal is unreasonable.

UNS attempts to portray its amended proposal as an innocuous placeholder, by claiming that there is no harm due to its willingness to be limited only to the revenue requirement set forth in its original application. However, as RUCO succinctly points out, the underlying premise of the Company's argument is fallacious unless the Commission were to agree with every revenue requirement position advocated by the Company. As discussed above, we have rejected a number of the arguments raised by UNS. As a result, the Company's revised position regarding application of FVRB, if it were adopted, would have a substantial impact on the rates that are established in this Decision.

The purpose of the Company's reliance on the cases it cites is unclear, given that no party disputes the concept that fair value rate base must be determined and applied in setting rates. The cases cited by UNS do not, however, stand for the proposition espoused by the Company (*i.e.*, that the Commission *must* apply the Company's WACC to FVRB to determine just and reasonable rates). In fact, those cases make clear that the Commission, although required to ascertain a company's fair value rate base and use that fair value rate base in determining rates, has broad discretion in how the rate-setting formula should be applied.

Even if we were inclined to consider the Company's proposal, its arguments are premature at best. Through his rebuttal testimony, UNS witness Grant suggests that the Commission must apply the WACC to fair value rate base pursuant to the *Chaparral City* decision (Ex. A-28 at 28). However, Mr. Grant's proposal ignores the explicit language of the Court's decision, which states: "the Commission asserts that it was not bound to use the weighted average cost of capital as the rate of return to be applied to the FVRB. The Commission is correct….[t]he Commission has the discretion to determine the appropriate methodology." (*Chaparral City, supra,* at p. 13, ¶17). Despite this unambiguous explanation, UNS would have us employ the very methodology the Court of Appeals specifically stated the Commission was not required to apply in setting rates.

Aside from the disingenuousness of the Company's argument, the current posture of the *Chaparral City* case is that it has been remanded to the Commission for further consideration. At this point, the Commission has not held hearings on the issue remanded by the Court, and thus no decision has been rendered by the Commission on the issue. Once the Commission issues a subsequent order in the remanded case, the Commission's decision may, or may not, be appealed to the Court of Appeals for a determination of compliance with the Court's remand. Thus, entirely aside from the inappropriateness of citing the unpublished *Chaparral City* decision as precedent, using it as the foundation for requiring a specific methodology in another unrelated case is clearly improper given that the Commission has been given an opportunity to cure the perceived defects in the *Chaparral City* case. Until that case has been decided under the Court's remand order, and the Court of Appeals has determined whether the Commission's Decision on Remand satisfies the Court's prior order, it is premature for UNS (or any other company) to suggest that the Commission must apply a particular methodology, especially a methodology that the Court specifically stated the Commission is not required to adopt.

We also believe that Staff has raised a number of relevant concerns with the Company's attempt to apply the WACC to FVRB without further modification. As Staff points out, there is no logical basis for applying such a methodology because investors have no expectation that they will earn a return on the excess between OCRB, which represents investor supplied funds, and FVRB, which represents unrealized paper profits. If the Company's proposal were to be adopted, the underlying basis of the cost of capital analysis would be called into question and would likely require substantial modification to avoid a result that grants excessive windfall returns to investors at the expense of ratepayers. We note that UNS states in its reply brief that, pursuant to the holding in *Ariz. Corp. Comm'n v. Arizona Water Co.*, 85 Ariz. 198, 203, 335 P.2d 412, 415 (1959), the Commission may not consider the argument raised by Staff regarding investor-supplied funds. The *Arizona Water* case is clearly distinguishable from the instant case, however, given the fact that the Court in *Arizona Water* was asked to consider only whether a recent purchase price paid for the utility company could be used by the Commission as the fair value of the utility for setting rates. No such set of facts is presented in this proceeding, and we do not believe the *Arizona Water* holding is applicable to the arguments presented by Staff.

For all of these reasons, we reject the Company's proposal on this issue.

AUTHORIZED INCREASE

Based on our findings herein, we determine that UNS Gas is entitled to a gross revenue increase of $5,257,468.

Fair Value Rate Base	$184,120,761
Adjusted Operating Income	9,621,507
Required Rate of Return	6.97%
Required Operating Income	12,833,217
Operating Income Deficiency	3,211,710
Gross Revenue Conversion Factor	1.6370
Gross Revenue Increase	$5,257,468

RATE DESIGN ISSUES

Customer Charge and Seasonal Rates

UNS Gas

UNS proposes in this case to increase the monthly customer charge for its largest customer class (Residential – R10) from $7 to $20 per month during the "summer" months (April through November) and from the current $7 to $11 per month during the "winter" months (December through March). The Company also proposes to decrease the current commodity rate for the R10 class from the current rate of $0.3004 per therm to $0.1862 per therm.[14]

UNS claims that its proposed rate design is intended to mitigate the cross-subsidization that currently exists between customers in colder climates and customers in warmer climates. According to the Company, it incurs approximately $26 per month in fixed costs to serve a customer, yet the residential customer charge is only $7 per month, with the remaining fixed costs being recovered through volumetric charges. UNS witness Tobin Voge stated that, as an example, a customer in Flagstaff pays substantially more towards the Company's fixed costs (through a higher percentage of volumetric charges) compared to a customer in Lake Havasu (Ex. A-18 at 8, Attach. TVL-1).

[14] Although the $0.1862 rate appears in UNS's original schedules (Ex. A-9, Sched. H-4), and in the Company's post-hearing brief, the Company's Final Schedules reflect a per therm rate proposal of $0.1844.

UNS argues that its proposed rate design would allow the Company to recover more of its fixed costs from all customers and would result in a more equitable policy in an environment of higher gas commodity costs. In support of the Company's position, UNS witness Grant cited a 2006 report from Moody's, which indicated that the volumetric approach to cost recovery is a faulty equation for LDCs that should be rectified through ratemaking (Ex. A-29 at 23). UNS also cites an AGA report, which suggests that, under a traditional volumetric rate design, a gas company's profits and earnings will decline if customers use less gas (Ex. A-37 at 2). The Company contends that it is time to address these alleged inequities through approval of higher monthly service charges and decoupling mechanisms (see discussion below regarding the Company's proposed "Throughput Adjustment Mechanism").

Under the Company's proposal, the monthly customer charge would be increased from $7 to an average of $17 per month (subject to the seasonal differences described above), which UNS claims would enable it to recover approximately 60 percent of its costs incurred in serving a residential customer (Tr. at 512). Because Staff and RUCO oppose the Company's seasonal customer charge proposal, UNS indicated that it is willing to accept a year-round customer charge of $17 (UNS Initial Brief at 46).

UNS asserts that the rate design proposals advocated by Staff and RUCO should be rejected. According to the Company, Staff's recommendation to increase the fixed monthly customer charge to $8.50, and RUCO's proposal to increase the customer charge to no more than $8.13, are an inadequate means of moving rates closer to the Company's cost of service. UNS asserts that its proposal to increase the customer charge by $10 over current levels is not drastic, will not result in "rate shock," and does not violate the principle of "gradualism," given the corresponding request to decrease the commodity charge.

UNS witness D. Bentley Erdwurm addressed the inequities between cold weather and warm weather customers and concluded that substantial cross-subsidization by customers in colder climates exists. He testified that the average customer in Flagstaff currently pays $133 more in annual margin costs than an average customer in Lake Havasu City for the same fixed costs (Ex. A-19 at 10). UNS argues that this inequity is especially unfair because customers in colder areas have little ability to reduce their overall bills due to the need to use natural gas for heating purposes.

With respect to the avoidance of rate shock and compliance with the principle of gradualism, UNS contends that the Staff and RUCO rate design recommendations focus too narrowly on the customer charge and fail to consider the Company's overall rate design proposal. The Company claims that the increase in the customer charge would be offset by the reduction of the commodity charge. UNS also asserts that the concepts of rate shock and gradualism must be balanced against other rate design elements, including rate stability and matching principles.

Finally, UNS argues that its rate design proposal does not eliminate the incentive for customers to conserve (by the proposal to reduce the commodity charge). According to the Company, even if its proposed per therm charge of approximately 18 cents were adopted, when that rate is combined with an estimated PGA charge of 60 cents per therm, the overall volumetric charge would be decreased by approximately 13 percent, which UNS claims is not enough to stifle conservation incentives.

<u>Mr. Magruder</u>

Intervenor Marshall Magruder opposes the Company's request to impose seasonal rates and to collect a higher percentage of rates from customers in warmer climates. Mr. Magruder claims that the Company's proposal would discriminate against customers in warmer areas and he suggests that customers choose whether to live in colder or warmer climates. He also asserts that UNS's proposed rate structure would send the wrong signal by rewarding high usage customers and penalizing low usage customers. He recommends instead that Staff's proposal to increase the customer charge to $8.50 be adopted.

<u>RUCO</u>

RUCO opposes the Company's recommendation to increase the monthly customer charge significantly. RUCO points out that UNS's proposal would shift more revenue to its fixed costs than it is seeking for its entire rate increase. As UNS witness Erdwurm admitted on cross-examination, the Company's entire requested revenue increase is approximately $10 million, yet it is seeking to recover an additional $16.4 million per year through the fixed monthly charge alone. In order to remedy this imbalance, UNS proposes to reduce the commodity charge by approximately $6.4 million (Tr. at 475-76). As a result, higher usage customers would experience a reduction in their bills, while lower usage customers would see a much higher percentage increase.

RUCO contends that some shifting of costs to the customer charge is appropriate and recommends that the current recovery of approximately 26 percent through the monthly fixed charge should be increased to 36 percent (under RUCO's revenue requirement recommendation) (RUCO Ex. 5 at 34). RUCO also disagrees with the Company's seasonal customer charge proposal. RUCO asserts that the justification offered by UNS in support of this proposal (to levelize customer bills) is not appropriate because the Company's customers already have a voluntary means to levelize their bills through an existing billing program. Ms. Diaz Cortez stated that if the Company believes more customers would benefit from levelized billing, it should make a greater effort to publicize the existing program's availability rather than seeking to impose a Commission-mandated seasonal rate design (*Id.* at 30).

Staff

Staff contends that the Company's rate design proposal in this case is designed to shift almost all of the risk of rate recovery to ratepayers and should therefore be rejected. Staff witness Steven Ruback presented Staff's rate design recommendation and stated that the UNS rate design would result in a "staggering" increase in the fixed customer charge for all classes of service (Ex. S-23 at 3). For the residential class, Mr. Ruback indicated, the Company's proposal would result in a customer charge increase of 185 percent in the summer period and 57 percent in the winter period (*Id.*). Mr. Ruback explained that, although the monthly charge increase would be partially offset by a lower volumetric charge, UNS's proposal presents a "serious front end loading problem, a decoupling issue and gradualism problem" (*Id.* at 4). He testified that it is not surprising that UNS would seek to increase the fixed customer charges and that such an approach is a common means that utilities use to lessen the risk of recovery (*Id.* at 6). Mr. Ruback stated UNS's proposal is unusual in that the Company has proposed to recover all of its increase, and some of the volumetric margin, through fixed charges (*Id.*).

According to Mr. Ruback, the Company's proposal represents a step towards a Straight Fixed Variable ("SFV") rate design, a concept employed by the FERC as a means of rationing pipeline design day capacity by price. Mr. Ruback stated that SFV rate design is inappropriate for retail distribution rate design because there is no need to ration retail distribution capacity. He further testified that UNS's rate design proposal "violates the well-established and long-standing regulatory principle that a utility should have a reasonable opportunity, not a guarantee to earn its allowed rate of return" (*Id.* at 9). Mr. Ruback indicated that he is aware of only one LDC, Atlanta Gas Light Company, that is permitted to employ the SFV rate design method to recover its distribution revenue requirement, and that exception to the general rule is mandated by state legislation that precludes the Georgia Public Service Commission from establishing an alternative rate design. Mr. Ruback stated that "other jurisdictions allow for reasonable fixed customer charges and reasonable fixed demand charges, but require that the bulk of the distribution revenue requirement be recovered over throughput" (*i.e.*, volumetric charges) (*Id.* at 10).

According to Staff witness Ralph Smith, Staff's rate design recommendation is based on the consideration of a number of factors, including cost of service; the desire to encourage energy conservation; the need to use gradualism in cases where rates are being charged, so that customers are not burdened with large rate increases; customer equity issues within and between rate classes; efforts to make rates and bills easier for customers to understand; revenue impacts on the Company; and other policy considerations. He stated that given all of these variables, it is understandable that rate design is considered more of an art than a science (Ex. S-26 at 2).

Under Staff's proposed rate design, the fixed monthly customer charge would be increased from $7 to $8.50 for residential customers, with no seasonal difference in the customer charge. Staff's proposed commodity charge for Rate R10 customers would increase to $0.3217 per therm, under Staff's revenue requirement recommendation (*Id.* at 9). Mr. Smith explained that if Staff's recommended revenue requirement and rate design were adopted, a residential customer (R10) using 100 therms of gas would experience a total bill increase from $115.48 to $119.11 (3.14 percent) (*Id.*). Staff asserts that its proposed rate design is reasonable and should be adopted by the Commission.

Conclusion

Although we understand that UNS would like to recover as much of its margin as possible through monthly customer charges, we do not believe it is reasonable to adopt a rate design that would impose a significant increase on customers based on where they live within the Company's service area. Under the Company's recommendation, residential customers with lower usage (*i.e.*, customers typically located in warmer climates) would bear the brunt of the revenue increase due primarily to the dramatic front-loading increase to the fixed monthly customer charge. As set forth in the UNS Final Schedules (based on UNS's proposed revenue requirement), in the "summer" months (April through November), a residential customer (R10) would experience an increase of 146 percent with 5 therms of usage, 118 percent with 10 therms of usage, and 82 percent with 20 therms of usage. During the "winter" months (December through March), the same customer would incur increases of 40 percent with 5 therms of usage, 28 percent with 10 therms of usage, and 13 percent with 20 therms of usage (UNS Final Schedules, Sched. H-4). While higher usage customers may realize lower increases, or even decreases (depending on usage), we do not believe that a dramatic increase imposed on lower usage customers is appropriate in this case. As we stated in the Southwest Gas Decision in rejecting a similar type of rate design proposal, "[such a] rate design would have the effect of encouraging greater usage of natural gas at a time when, by all accounts, an increase in demand for natural gas is coupled with shortages in supply. We do not believe that it is appropriate to send a signal to customers of 'the more you use, the more you save,'" (Decision No. 68487, at 37).

As discussed by Staff's witnesses, movement towards cost-based rates is just one of the many factors that must be considered in designing rates. The goal of moving closer to cost-based rates must be balanced with competing principles such as gradualism, fairness, and encouragement of conservation. Based on the testimony and evidence presented in the record, and considering the arguments raised regarding competing principles of the rate design equation, we believe that Staff's rate design recommendation appropriately makes significant movement towards cost-based rates and provides a reasonable level of protection for the customers who are affected by this base rate increase. Accordingly, we adopt Staff's recommended monthly charges, as set forth in the attachments to Exhibit S-27, with the accompanying commodity charges based on Staff's rate design flowing from the revenue requirement established in this Order.

For a residential customer on Rate R10, the fixed monthly customer charge would increase from $7 to $8.50, and the volumetric charge would increase from $0.3004 to $0.3270 per therm. Based on these rates, a residential customer with 20 therms of usage would experience an increase in monthly base rates of 15.6 percent (from $13.01 to $15.04) and an overall monthly increase (including the cost of gas) from $28.70 to $30.73 (7.1 percent). The same customer with typical January consumption (87 therms) would see an increase in base rates of 11.5 percent (from $33.13 to $36.94) and an overall increase (including the cost of gas) from $101.37 to $105.18 (3.8 percent).

Throughput Adjustment Mechanism

UNS Gas

In its application, UNS proposed a Throughput Adjustment Mechanism ("TAM") which would increase or decrease the collection of volumetric revenues to match anticipated levels. The Company claims that the TAM would allow it to implement energy conservation programs without the concern that its revenues would be diminished if the conservation measures were successful. UNS indicated that under its proposed TAM, under-recovery or over-recovery of revenues during any given period would be trued-up in future periods through the use of a volumetric surcharge or credit.

As explained by Company witness Erdwurm, the TAM is a type of decoupling mechanism that has growing support from regulatory and environmental organizations. In his testimony, Mr. Erdwurm stated that organizations such as the Natural Resources Defense Council ("NRDC"), the American Council for an Energy Efficient Economy ("ACE"), and the AGA have expressed support for rate mechanisms that decouple utility retail sales from recovery of fixed costs (Ex. A-19 at 17-18). He claims that a NARUC Resolution encourages state commissions to adopt rate designs that include decoupling mechanisms such as the TAM (*Id.* at 18). The Company also introduced a newsletter issued by the AGA indicating that decoupling mechanisms have been implemented in 10 states (Ex. A-37).

According to UNS, the Company's return is highly dependent on customer usage because of the volumetric nature of its rates. UNS witness Tobin Voge's testimony stated that a warmer than normal winter will cause customer usage, and thus Company revenues, to decline, thereby rendering UNS unable to collect its full fixed costs (Ex. A-18 at 15). On the other hand, during a colder than normal winter, UNS would experience a surge in revenues. The Company contends that the TAM would make customer bills less volatile by evening out wide fluctuations due to weather.

Mr. Voge's testimony indicates that in order to implement the proposed TAM, a base use per customer ("UPC") must first be established. Under the Company's proposal, a separate base would be established for residential, small volume commercial, and small volume public authority customers. The UPCs would be calculated by dividing calendar year therm sales by average number of customers. The difference between the actual and base UPC would then be multiplied by the 2005 base number of customers, and the margin rate for the customer class, to determine the throughput adjustment in dollars (*Id.* at 12-13).

The Company asserts that, by minimizing the impact of weather on customer bills, the TAM would provide a more equitable rate design that ensures that customers do not pay more for the Company's fixed costs than they would under normal weather conditions (Ex. A-19 at 15). UNS also claims that the TAM would encourage conservation by reducing the conflict between conservation efforts and the Company's financial stake in the volumetric revenues associated with usage (Ex. A-18 at 15).

UNS dismisses the validity of RUCO's arguments that the TAM would eliminate the incentive for customers to conserve. The Company argues that, under its proposal, all customers would receive bills with identical TAM adjustments based on cumulative system usage, not personal household consumption. As a result, UNS claims, each individual customer would continue to benefit from conservation efforts because the individual customer's actions would represent only a small portion of the usage data reflected in future TAM adjustments.

UNS also disputes arguments made by Staff and RUCO that the TAM would remove the Company's risk of revenue recovery. The Company claims that the TAM would not alter the ability or inability to recover base rates established in the rate case, and that rising capital expenditure requirements associated with customer growth would continue. UNS also argues that its proposed TAM differs from the "conservation margin tracker" decoupling mechanism that was rejected in the

Southwest Gas case (Decision No. 68487 at 33-34). According to UNS, the TAM differs from the decoupling mechanism proposed by Southwest Gas in the following ways: the TAM would cover all small volume customers, not just residential customers; UNS has provided examples of the calculations needed to implement the TAM; and UNS is willing to consider the creation of a deferred adjustment account (Ex. A-18 at 14). Finally, UNS claims that it has pledged to continue supporting demand-side management ("DSM") programs, regardless of adoption of the TAM. The Company argues, therefore, that it cannot be accused of attempting to use its TAM proposal as leverage for its continued support for DSM.

RUCO

RUCO witness Marylee Diaz Cortez testified regarding the reasons for RUCO's opposition to the proposed TAM. She stated that the TAM would cause customers to pay for a fixed amount of consumption regardless of their actual usage and would remove any risk to the Company associated with revenue recovery (RUCO Ex. 5 at 30-31). Ms. Diaz Cortez testified that variations in consumption are already addressed by the rate case process based on weather normalization of revenues (Tr. at 706).

RUCO argues that it is not appropriate for the Commission to provide a guarantee of a certain stream of revenues because the regulatory process is intended to provide only the opportunity for a company to recover its revenue requirement. Ms. Diaz Cortez stated that UNS already has an exclusive service territory and a captive customer base, giving it a low business risk. She also indicated that the authorized rate of return set by the Commission compensates the Company for any business risk that may exist (RUCO Ex. 5 at 31).

RUCO next argues that approval of the TAM would present a departure from the historic test year concept, which RUCO claims is required under the Commission's rules and the Arizona Constitution. Finally, RUCO contends that Southwest Gas experiences greater decreases in consumption due to conservation than does UNS Gas, yet the Commission previously rejected Southwest Gas' decoupling mechanism proposal. RUCO points out that the Commission expressed concern that the decoupling mechanism proposed by Southwest Gas could have resulted in disincentives for customers to conserve (Decision No. 68287 at 34), and the same concern exists with respect to UNS Gas's proposed TAM.

Mr. Magruder

Mr. Magruder opposes adoption of the Company's proposed TAM for many of the same reasons identified by Staff and RUCO. He argues that UNS should not be insulated from risk and that customers should not have to pay for gas they have not used.

Staff

Staff witness Steven Ruback expressed several concerns with the Company's proposed TAM. Mr. Ruback stated that the TAM is essentially an automatic adjustment clause and that such adjustors traditionally are intended to recover volatile costs that, if left unrecovered, could jeopardize a company's financial health. He indicated three requirements for the types of costs generally allowed to be recovered through adjustor mechanisms: the costs must be large enough to jeopardize the utility's financial health, they must be volatile, and they must be substantially beyond a company's control. He claims that the TAM does not meet these tests because traditional ratemaking has not left UNS in poor financial condition, non-gas costs are not extremely volatile, and non-gas costs are within management's control (Ex. S-23 at 16).

Mr. Ruback also asserts that UNS already has in place two types of revenue decoupling mechanisms - the fixed customer charge, which is independent of throughput, and the PGA, which protects the Company from volatile spikes in the cost of gas (*Id.* at 16-17). At the hearing, Mr. Ruback testified that, in his opinion, "the TAM is overly broad because it compensates for reduced sales from anything – from weather variation, from economic activity, to loss of costs, to high commodity charges." (Tr. at 796). He conceded that it is not just UNS Gas's proposal he dislikes, stating, "I haven't seen a TAM I liked yet." (*Id.*) However, Mr. Ruback contends that adoption of the TAM would represent "piecemeal ratemaking" because there is no commensurate opportunity in the mechanism to consider offsetting adjustments related to cost of service reductions, cost of capital changes, and changes in customer allocation factors (Ex. A-23 at 14).

Finally, Staff points to the Southwest Gas rate case, in which the Commission rejected a similar proposal. Staff acknowledged that the Commission directed Southwest Gas and interested stakeholders to examine further decoupling mechanisms, and Staff indicated that it is willing to engage in discussions outside of this case regarding such mechanisms. However, Staff argues that UNS's proposal should be rejected based on the record in this case.

Conclusion

We do not believe the record supports adoption of UNS Gas's proposed decoupling mechanism in this case. In the Southwest Gas case, we cited a number of concerns with a decoupling mechanism that was similar to the TAM proposed by UNS Gas in this proceeding. We pointed out in the Southwest Gas Order that decoupling mechanisms require "customers [to] provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk." (Decision No. 68487 at 34) We also noted that, under such a mechanism, customers would "be required to pay for gas that they have not used in prior years, a phenomenon that could result in disincentives for such customers to undertake conservation efforts…[and would be] faced with a surcharge for not using 'enough' gas the prior year." (*Id.*) We therefore directed Southwest Gas to find rate design alternatives that truly encourage conservation and to engage in discussions with affected stakeholders to pursue implementation of a decoupling mechanism through the DSM policy process or through a proposal in Southwest Gas's next rate case (*Id.*).

Although the Company attempts to distinguish its TAM from the mechanism rejected in the Southwest Gas case, the differences are insignificant compared to the overall similarities between the proposals. The first difference cited by the Company, that it is willing to apply the TAM to all small volume customers, is not persuasive given Southwest Gas's concession that it was also willing to extend its decoupling mechanism to a broader base of customers (*Id.* at 31). The next difference claimed by UNS is essentially that its proposal provided a greater level of detail, by including examples of calculations that would be used to implement the TAM, than did that of Southwest Gas. As indicated in the passages quoted above, our primary concern with the Southwest Gas proposal was not specifically with the lack of implementation details, but rather with a concept that would provide the utility with a level of risk insulation, while possibly discouraging conservation efforts through imposition of a surcharge on an entire class of customers if that class did not use "enough" gas the preceding year. The final difference claimed by UNS is its offer "to consider the creation of a deferred throughput adjustment account." (Ex. A-18, at 14) Again, the distinction identified by UNS is not substantive in nature but instead provides an alternative means of accounting for the proposed surcharge. The Company's alternative accounting technique does not, however, address the underlying concerns clearly expressed regarding the Southwest Gas decoupling mechanism. We see no reason, based on the record in this proceeding, to depart from our finding in the Southwest Gas Decision regarding a proposed decoupling mechanism.

Having rejected UNS Gas's TAM proposal, we encourage the Company to engage in discussions with other stakeholders affected by this issue; to participate in the ongoing DSM workshops before the Commission; and, if possible, to develop a decoupling mechanism that does not suffer from the types of deficiencies identified by the parties in this case.

Demand-Side Management Programs

UNS Gas

UNS Gas proposes to implement several new DSM programs, including a residential furnace retrofit program, residential new construction home program, commercial HVAC retrofit program, and commercial gas-cooking efficiency program. The Company claims that these four new programs will require funding of $916,616 and that a proposed expansion of its low-income weatherization ("LIW") program will cost an additional $135,000, for a total annual DSM portfolio expense of $1,051,616 (Ex. A-15 at 13-15).

UNS states that it is largely in agreement with Staff's DSM recommendations, specifically with respect to submission of the programs for review by Staff. UNS witness Denise Smith testified that the Company prefers to have the new programs approved in this case so that they may be implemented as soon as possible (Tr. at 518). On May 4, 2007, the Company filed its DSM program proposals in a separate docket for Staff's review (Docket No. G-04204A-07-0274).

Ms. Smith indicated that the Company has agreed to use Staff's recommended Societal Cost Test to determine the effectiveness of the DSM programs, despite her reservations regarding how that test would be applied (Ex. A-21 at 4, 7; Ex. A-22 at 2). However, Ms. Smith stated that the other DSM tests - including the Participant Test, Program Administrator Cost Test, Total Resource Cost Test, and Rate Impact Measure Test - should also be utilized, to provide a full analysis of program effectiveness (Ex. A-21 at 7). Ms. Smith also agreed that the Company would continue to provide semi-annual reports to the Commission, but stated that the Company would seek at a later time to move to an annual reporting requirement (Ex. A-22 at 14).

With respect to calculation of the DSM adjustor mechanism, Ms. Smith indicated that UNS agrees initially to limit recovery to 25 percent of the new program costs ($230,000) and LIW program costs ($113,400), plus the cost of the baseline study that is needed to evaluate thoroughly the effectiveness of the programs ($82,000). The total amount of $425,400 would translate to a DSM adjustor surcharge of $0.0031 per therm, when divided by total test year therms of 138,223,864 (*Id.* at 3).

<u>Mr. Magruder</u>

Mr. Magruder indicates that he is a proponent of DSM programs but believes that additional review of the Company's programs is necessary prior to approval. However, he suggested that all the necessary information regarding the programs should be submitted to Staff as soon as possible so that the programs could be addressed in the Recommended Opinion and Order in this case, to allow the parties an opportunity to comment regarding the findings determined therein. He also suggested that an integration of the UNS Gas and UNS Electric DSM programs could be consolidated in the pending electric rate case for UNS. At the same time, however, Mr. Magruder recommended that UNS Gas's DSM programs should not be funded until after public hearings are held on those programs. He proposed that the Energy Smart Home ("ESH") program should include training of local city/county building inspectors to meet Energy Star requirements, using RESNET personnel. Finally, Mr. Magruder recommended that in-home energy audits should be continued due to their value (Magruder Brief at 38-41).

<u>Staff</u>

Staff witness Julie McNeely-Kirwan presented Staff's position regarding the Company's proposed DSM programs. She recommended that the LIW funding ($113,400) and 25 percent of the new program costs ($229,154) should be included in the initial DSM surcharge, but that UNS Gas's portion of the baseline study costs ($82,000) should not be included in the surcharge initially (Ex. S-

40 at 1-2, 8). Based on this recommendation, Staff calculated an initial DSM surcharge of $0.0025 which it recommends be established in this case (*Id.*).

Ms. McNeely-Kirwan also agreed with UNS that the DSM adjustor reset date should require a filing by April 1 of each year, with an adjustment date of June 1. As indicated above, UNS agreed with Staff's recommendation to require semi-annual DSM reports. In her direct testimony, Ms. McNeely-Kirwan recommended that the Company file a comprehensive DSM portfolio, which UNS has apparently provided through an attachment to Denise Smith's testimony (Ex. A-23), as well as in the separate docket cited above. However, Staff opposes approval of specific programs in this proceeding and recommends approval in a separate docket, consistent with past practice for other companies (Tr. at 1141).

Conclusion

We agree with Staff's recommendation to set the DSM adjustor surcharge at an initial level of $0.0025, which reflects exclusion of the baseline cost study. As indicated in Staff's recommendation, the costs of the baseline study may be included in a subsequent reset of the adjustor once sufficient justification of the allocated costs has been submitted for Staff's review. UNS agreed with Staff's proposal to shift the adjustor filing date to April 1, with an adjustor date of June 1, as well as with Staff's recommendation that semi-annual reports be required for the DSM programs. We also agree with Staff that the appropriate forum for a full review of the specific DSM programs is in the separate docket in which there is an application currently pending. This approach is consistent with that required for other companies, including APS and Southwest Gas (*See, e.g.*, Decision No. 68487, at 61-63).

Low-Income Customer Programs

UNS Gas currently offers several low-income assistance programs. The Customer Assistance Residential Energy Support ("CARES") program (Rate Schedule R12) provides a per therm discount to customers meeting eligibility requirements during the months of November through April. Warm Spirits is an emergency bill assistance program offered to eligible low-income customers. As discussed above, UNS also offers the LIW program, the costs of which would now be recovered through the DSM adjustor mechanism.

UNS Gas states that, in addition to offering these specific programs, it will continue to work with the ACAA on low-income customer issues. The Company contends that it is committed to automatically enrolling customers eligible for the Low-Income Home Energy Assistance Program ("LIHEAP") into the CARES program (Ex. A-16 at 8) and will continue to expand its outreach efforts. Those outreach efforts include distribution of CARES applications to local assistance agencies, public libraries, and municipal buildings and promotion of the program through residential bill inserts (Ex. A-17 at 4). UNS also contends that it is willing to explore opportunities to increase the marketing of low-income programs and to increase LIW funds to low-income agencies.

Miquelle Scheier testified on behalf of ACAA regarding various low-income customer issues, including CARES customers (ACAA Ex. 1). Ms. Scheier opposed the Company's proposal to increase the customer charge for low-income customers; urged the Commission to increase marketing efforts for the R12 tariff; requested the Commission to require automatic enrollment of LIHEAP customers into the CARES program; sought the elimination of payday loan offices as payment centers for cash-paying customers; requested that bill assistance money be increased from $21,500 to $50,000; asked that LIW funding be increased to $200,000, and that $20,000 of that amount be directed to community volunteer weatherization efforts; and requested that the proposal to reduce the due date for bills be denied (*Id.* at 2).

<u>CARES Program</u>

Customers receiving service under the CARES program currently pay the same basic monthly charge of $7 as do other residential customers, but CARES customers receive a per therm discount of $0.15 on the first 100 therms of usage during the months of November through April. As described above in the rate design section of the Order, UNS proposed a seasonal monthly charge increase to $20 from December through March and to $11 from April through November. The Company also proposed to decrease the volumetric charge applicable to all customers. For CARES customers, UNS proposed a year-round customer charge discount of $6.50 per month, along with the reduction of the commodity charge discussed previously. Under the Company's recommendation, CARES customers' fixed monthly charge would increase from $7 to $13.50 from April through November, but would decrease to $4.50 per month from December through March. The same volumetric charges would apply to all residential customers.

The Company claims that its proposal would increase CARES customers' bills modestly, with an increase of $1.12 per month during winter months (assuming100 therms of usage), and $4.21 per month during summer months (assuming 20 therms of usage) (Ex. A-9, Sched. H-4). UNS contends that some higher usage CARES customers may actually see a rate decrease due to the Company's proposed commodity charge reduction.

Staff recommends that the current monthly charge of $7 be retained for CARES customers and that they continue to receive the current $0.15 per therm discount for the first 100 therms of usage during the months of November through April (Ex. S-40 at 2). Staff contends that its recommendation provides a price signal that would encourage conservation by CARES customers during winter months, because usage over 100 therms during those months would incur a substantial increase. Staff witness McNeely-Kirwan stated that the Company's rate design proposal would provide a disincentive for conservation, given UNS's recommendation to decrease the volumetric charge for all therms of usage (*Id.* at 3).

Given our prior rejection of UNS's seasonal customer charge and across-the-board volumetric rate reduction recommendation, the application of the Company's proposal to CARES customers is effectively a moot point. We agree with Staff that keeping the current customer charge in effect for CARES customers, and retaining the current winter volumetric discount for the first 100 therms, will help mitigate the effects of the rate increase approved in this case and will continue to provide a rate structure for the low-income customers enrolled in the program that offers an opportunity to reduce their overall bills through conservation efforts. We therefore adopt Staff's recommendation on this issue.

<u>Warm Spirits Program</u>

Warm Spirits is a program, funded by customer contributions, that provides emergency bill payment assistance to low-income customers. UNS witness Gary Smith testified that UniSource Energy promotes the program through bill inserts and bill messages encouraging customers to contribute to the program (Ex. A-15 at 10-11). The proceeds of the contributions are distributed to local service agencies, which assist qualified low-income customers in paying their bills, most often during the winter heating season. Mr. Smith stated that UNS Gas matches customer donations dollar-for-dollar with funds provided by UniSource shareholders. He indicated that UniSource made a one-time donation of $50,000 to the program in 2004 and that UNS matched $24,000 in donations in 2005. Mr. Smith testified that the Company would continue to match customer contributions on a dollar-for-dollar basis (*Id.*). As indicated above, ACAA proposes that the Commission require UNS to provide funding for Warm Spirits in the amount of $50,000 per year (ACAA Ex. 1 at 2).

The Company originally proposed that the Low-Income Weatherization Program include $21,600 in emergency bill assistance, separately and in addition to that already available through Warm Spirits. The $21,600 would have been part of the UNS Gas DSM portfolio and funded through the DSM adjustor. Staff objected because emergency bill assistance is not DSM and should not be funded as DSM. Staff proposed, and the Company agreed, that the $21,600 be moved into Warm Spirits and funded though base rates. We agree that the $21,600 in additional emergency bill assistance should not be funded through the DSM adjustor and that this amount should be moved into Warm Spirits and funded through base rates.

We believe that the Company's matching contributions to the Warm Spirits program, which currently amount to approximately $20,000 to $25,000 per year, are a reasonable commitment at this time. However, we encourage the Company to continue to promote the existence of the program and the ability for customers to make voluntary contributions.

It is not clear in the record whether UNS Gas currently has a section on customer bill payment stubs that allows customers to check a box to indicate that they would like to make a contribution at the time they write out their payment checks. This issue was raised in the Southwest Gas case, wherein we directed Southwest Gas to modify its billing statements to allow voluntary contributions (Decision No, 68487, at 59-60). In that Order, we pointed out that a contribution line is offered to APS customers and that "inclusion of a line on customer bills is preferable to [relying solely] on a bill insert, which may be discarded when customers open their bills." (*Id.* at 60) Therefore, if UNS Gas does not currently have in place a bill statement contribution option, it shall implement the change within 60 days of the effective date of this Decision.

Payments at Payday Loan Stores

In 2006, UNS closed local offices in Prescott, Cottonwood, Flagstaff, and Show Low[15] (Tr. at 434-35). These closings coincided with the Company's consolidation of its Tucson call center operations for all of the UniSource operating affiliates, which UNS claims was intended to improve customer service while at the same time cutting the Company's operating costs (Tr. at 436-40). At the time these offices were being closed, customers were notified that future payments could be made at various ACE Cash Express locations and other specified "cash only" stores (Ex. A-16, Attach. GAS-3). For payments made at these so-called "payday loan" stores in areas where UNS does not have a local office, UNS pays the fee charged by the payday loan stores, but customers who pay at such stores in an area that has a local office (*i.e.*, Kingman, Lake Havasu, and Nogales) must pay a $1 fee in order to make a payment at the payday loan stores (*Id.* at 8).

ACAA witness Scheier expressed concern that cash paying customers, especially low-income customers, could be vulnerable to predatory lending practices at the payday loan stores. She testified that ACAA objects to the use of such stores because "it places already vulnerable customers in a more vulnerable situation." (ACAA Ex. 1 at 13) Ms. Scheier also stated that she did not understand why the Company could not place "ATM-like kiosks" that accept cash payments in local areas (*Id.*). She further claimed that some low-income clients had been encouraged to take out loans when they made payments at the payday loan stores (ACAA Ex. 2, at 2).

Mr. Magruder also opposes use of payday loan stores for taking payments. He suggested that other payment agents should be found by the Company or, alternatively, that a Company employee may need to be on-location at the payday loan stores during weekdays (Magruder Brief at 37).

UNS witness James Pignatelli testified that UNS does not send customers to predatory lenders by its acceptance of payments at payday loan stores. He indicated that customers could obtain loans from payday loan stores even if the Company had not closed its local offices or had in place ATM-like kiosks (Ex. A-3 at 1). Mr. Pignatelli stated that the decision to close some branch offices and

[15] UNS continues to operate local offices in Kingman, Lake Havasu, and Nogales.

offer alternative locations for cash-paying customers was made to keep down costs for all customers, including low-income customers (*Id.*).

UNS witness Gary Smith claims that Ms. Scheier's comments regarding customers' being encouraged to take out loans from the payday loan stores is not consistent with information the Company has received from payday loan store managers (Ex. A-17 at 5). He contends that UNS is not encouraging customers to utilize payday loan services at these locations (Ex. A-16 at 9). During the hearing, Mr. Smith testified that APS also utilizes payday loan stores for acceptance of cash payments, as does Citizens Frontier Communications (Tr. at 343). He indicated that UNS contacted grocery stores and local banks in the Prescott and Chino Valley areas about their willingness to accept payments, but was turned down. Mr. Smith stated that UNS was looking into a joint arrangement with APS under which a payday loan store in Flagstaff would have a dedicated window available for payment of utility bills, separate from the store's main counter. He also testified that the Company was discussing with APS the possibility of using a non-payday loan store site for acceptance of payments (Tr. at 344-47).

Although we encourage UNS to seek out cost-cutting opportunities, we are concerned when those efforts result in the diminution of service to customers. We understand the Company's call center consolidation decision was intended to provide consistency between the UniSource affiliates and to reduce costs in the long-term. On cross-examination, the Company's witness sought to justify the office closings on the basis that not enough people used the local offices to justify their continuation, and that more customers use the payday loan stores due to their convenience (Tr. at 342-43). However, the closing of a number of local offices, especially in northern Arizona, represents not just the elimination of a nearby location for making payments, but also the loss of an office where customers could talk to a representative of the Company face-to-face to work out payment arrangements or receive assistance in signing up for available programs.

We believe that additional efforts should be undertaken by UNS to explore fully all available alternatives for the provision of service to customers. We therefore direct the Company to make every reasonable effort to determine whether other payment locations may be utilized either in addition to, or in lieu of, the payday loan stores currently used by UNS. These efforts should include, but not be limited to, joining with other utilities to enlist alternative agents, such as banks or grocery stores, to accept cash payments and to explore of opening joint local offices to offset costs and any other alternatives that may enhance customer service without exposing customers to the potential of being solicited by predatory lenders in the course of making a utility payment. UNS shall file a copy of its recommendations consistent with this directive within 90 days of the effective date of this Decision.

Proposed Changes to Rules and Regulations

UNS proposed a number of changes to its existing Rules and Regulations governing service. Among those proposed changes are increases to charges for service lines and main extensions and a proposal to reduce the period, from 15 days to 10 days, that customers have to pay their bills before the bills are considered past due.

Line and Main Extension Policies

UNS proposes amendments to its Rules and Regulations (*i.e.*, tariffs) that it claims would ensure that developers and new customers pay a fair cost for infrastructure associated with connecting new developments to the UNS Gas system (Ex. A-15 at 19-20). As described by UNS witness Gary Smith, the Company proposes changes to both its service line and main extension policies (*Id.* at Sched. GAS-2). The Company's proposals, as set forth in its brief, are as follows:

1. For a new gas service line, the customer would be required to reimburse the Company at a rate of $16 per foot on the customer's property (the current rate is $8 per foot). For customers who provide the trench for the service line, the rate would be $12 per foot (*Id.* at 19).
2. Under the Company's proposal, there would be no free footage, so developers would pay the entire amount up front (subject to refund) (Tr. at 386-87).
3. In its effort to comply with A.A.C. R14-2-307, UNS prepared an incremental contribution study ("ICS") to determine an estimate of the costs and benefits of adding a customer to the system. Under the Company's proposal, the ICS component would be modified to reduce the credit applied to new customers or developers per service line or main extension (thereby increasing the required advances from new customers and developers). According to the Company, this change would ensure that the cost burden is initially placed on new customers and developers for main extensions or line extensions, subject to refund over a five-year period (Tr. at 384-87, 919; Ex. A-35).
4. For line extensions over $500,000, UNS would add a gross-up amount equal to the Company's estimated federal, state, and local income tax liability in advance (Ex. A-15, Sched. GAS-2).

UNS estimated that the changes described above would result in an additional $3.6 to $3.8 million per year in contributions, on average (Ex. A-30; Tr. at 915). The changes would result in an increased contribution from new customers/developers, from the current amount of approximately $300 to more than $500 per connection (*Id.*). In response to questions from Commissioner Mayes, UNS later offered the following two additional alternative proposals[16]:

1. Eliminating of the ICS and retaining tariff language requiring new customers to pay for the entire length of the new service line to their property, resulting in an additional estimated $1.2 million in contributions (Ex. A-31; Tr. at 916); and
2. Requiring that new customers/developers pay for excess flow valves (approximately $250 each), which will become a mandatory requirement for new service lines beginning in July 2008 (Ex. A-32; Tr. at 1067).

UNS points out that Staff witness Ralph Smith testified that the Company's line extension and main extension proposals (not including the alternatives) appear to be reasonably supported by the Company (Ex. S-25 at 64-67; Ex. S-27 at 44). Mr. Smith indicated that the Company's proposal appears to provide a feasibility study in compliance with Commission requirements (Tr. at 869-71). Therefore, Staff does not oppose the Company's tariff change requests on these issues. UNS also argues that its proposed ICS helps the Company specifically tailor a new customer's or developer's up-front contribution requirement rather than imposing a flat one-size-fits-all contribution requirement. UNS adds that because not all developments become fully built-out within the allotted five-year term of advance refunds, the balance of advances would become contributions after that five-year period (Tr. at 1055). UNS asserts that its proposals seek to hold developers and new customers responsible for a fair share of costs associated with serving growth.

We find that the Company's line and main extension proposals are a reasonable means of increasing the up-front contributions required from new customers and developers to connect to the UNS Gas system. However, we also believe that one of the alternatives suggested by the Company,

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[16] UNS witness Gary Smith testified that the Company does not advocate adoption of these alternatives because he believes the Company's proposal, if combined with the alternatives, would require a significant increase in contributions by new customers and developers, from the current average of approximately $310 per connection to nearly $1,000 per connection. He stated that requiring substantial increases in required contributions could put UNS Gas at a competitive disadvantage, relative to the construction of homes using all electric or propane, and thereby lessen the Company's ability to add new service connections (Tr. at 1069-72).

the charge for excess flow valve installation, should be implemented by UNS to further increase the amount required for system connections. Since the excess flow valves will become mandatory in 2008, it is reasonable that the costs to install those devices should be included in the contributions, i.e. non-refundable, required from new customers/developers.

As set forth in Exhibit A-30, it is estimated that institution of these combined measures would cause the average contribution per service line to increase from the current amount of approximately \$300 to \$383 in 2007, \$635 in 2008, and \$760 in 2009 and beyond. The net result is that new customer/developer contributions would more than double within the next year and would continue to increase in the following year. Although the contributions are actually advances that are refundable within the first five years, to the extent a development is not built out within that five-year period, the balance of the up-front contributions would become nonrefundable and would not be includable in rate base.

We believe that our finding on this issue achieves a result that is consistent with the rate design concept of gradualism because, although it represents a significant increase in the up-front contribution required to be financed by new customers/developers, it keeps intact the ability of developers to recapture all or part of the initial investment. At the same time, as described by the Company's witnesses, approval of this modified proposal avoids the potential competitive disadvantage that would be faced by UNS Gas if a fully nonrefundable hook-up fee were to be implemented suddenly. We recognize that, over the long-term, increasing the number of customers on the system and the revenues associated with those customers should provide a benefit to all customers. While we believe the extension measures approved in this Order are reasonable at this time, we direct UNS Gas to investigate fully the issue of developer contributions and present in its next rate case viable alternatives to the proposal adopted herein, including but not limited to nonrefundable hook-up fees and other measures that would hold harmless existing customers and require greater contributions to ensure that growth pays for itself.

Reduction of Bill Payment Due Date

UNS proposes to modify its billing terms in its tariffs by reducing from 15 days to 10 days (from the time the bill is rendered) the time for customers to pay bills before the bills are considered past due. The Company's proposed change would make its billing practices consistent with the requirements of the Commission's Rules, as set forth in A.A.C. R14-2-310(C). UNS witness Gary Smith contends that even under the proposed billing change, customers would have plenty of time to pay bills before late payment charges would apply or termination of service would be implemented (Ex. A-16 at 4). According to Mr. Smith, after the 10-day payment period, customers would have an additional 15 days before a late payment charge would be imposed, for a total of 25 days. At that point, the bill would be considered delinquent, but termination-of-service procedures (*i.e.*, notice of termination) would not commence for an additional 5 days, and several additional days would likely pass before actual termination occurred. Mr. Smith indicated that the Company would be able to waive the late fee if a customer presented good cause for late payment (*Id.*).

RUCO, ACAA, and Mr. Magruder oppose the Company's proposal to reduce the time to pay a bill. RUCO argues that, although the Company's proposal is consistent with the minimum requirements of the Commission's Rules, the only advantage identified by UNS is that the proposed tariff change would bring consistency to the three affiliated utility companies that are served by the UniSource consolidated call center (Tr. at 355). RUCO claims that the proposed payment dates are so short that a customer could go on vacation and return home to find the gas service shut off (RUCO Ex. 5 at 35). RUCO witness Diaz Cortez stated that RUCO has received calls from customers opposing the proposed changes and that a more flexible payment schedule should be retained. Ms. Diaz Cortez stated that the Company is already compensated, through the working capital calculation, for the delay that exists between the rendering of bills and the receipt of payment from customers (*Id.* at 36). RUCO also contends that the call center consistency rationale offered by the Company does not support the proposed changes because the call center representatives must be trained regarding gas-specific issues anyway. RUCO asserts that the payment schedule change would provide only a minimal benefit to the Company, but customers would bear the burden of the proposed changes.

Staff did not oppose the Company's proposal, but recommended a six-month waiver of the late payment penalty charge. Staff argues that during this initial six-month period, the penalty should be waived from day 10 to alleviate the hardship on customers from the proposed billing change.

According to UNS witness Gary Smith, the Company agrees with Staff's recommended six-month waiver period before the billing changes go into effect (Ex. A-16 at 3-4).

We agree with UNS that the proposed billing changes are reasonable. The billing changes would make the Company's tariffs consistent with the Commission's Rules and would remove an inconsistency among the billing tariffs currently in effect for the UniSource affiliates. The proposed change would also allow the customer call center representatives to have a single set of rules in place for all of the UniSource affiliates, which should minimize potential errors that may occur when information regarding delinquent bills and/or termination of service is provided to customers. In addition, as the UNS witness pointed out, a bill would not be subject to a late payment charge until at least 25 days after the bill is rendered, and a termination of service notice for nonpayment could not occur sooner than 30 days following issuance of a bill. We believe that these timeframes provide an adequate period for customers to either pay a bill or seek alternative payment arrangements prior to being subjected to a penalty or termination of service. We therefore approve the Company's proposed changes to its billing tariffs. However, in accordance with the Company's agreement to abide by Staff's six-month waiver recommendation, we direct UNS Gas not to implement the approved billing change for a period of six months following the effective date of this Decision.

Prudence of Gas Procurement Practices and Policies

As described above, this consolidated proceeding includes Docket No. G-04204A-05-0831 (the Prudence Case), which relates to an audit conducted by Staff of UNS Gas's natural gas procurement practices and policies during the period of September 2003 through December 2005 (Tr. at 761). Staff retained Jerry Mendl, President of MSB Energy Associates, Inc., and George Wennerlyn, President of Select Energy Consulting, LLC, to conduct the Prudence Case audit.

Based on his review of the Company's procurement practices during the audit period, Mr. Mendl concluded that the Company's procurement strategy during the audit period was reasonable (Ex. S-20 at 1). He reiterated at the hearing that "[UNS Gas's] natural gas procurement strategy that was set forth in the price stabilization policies was reasonable over the review period." (Tr. at 761)

Mr. Wennerlyn reached the same conclusion regarding the Company's practices during the 2003-2005 audit period. He stated that the Company's gas procurement practices and policies during that period "achieved appropriate objectives of a purchasing strategy which balances reliability, cost, and price stability. The purchases were reasonable and prudent." (Ex. S-18 at 4-5)

There is no dispute on the issue of prudence during the identified audit period. We therefore agree that the Company's natural gas procurement practices and policies during the audit period of September 2003 through December 2005 are deemed prudent.

<u>Price Stabilization Policy</u>

This piece of the prudence equation relates to the request by UNS Gas for the Commission to approve its current "Price Stabilization Policy" ("PSP"). The basis for UNS Gas's request for what is effectively prudence pre-approval was described as follows by Company witness David Hutchens as follows:

> We believe that instead of the Commission attempting to second guess, after the fact, the individual acts that UNS Gas transacted in connection with gas procurement and hedging, it is more productive and beneficial to customers that the Commission review the policies and approve them prospectively. That way the Company will know the clear direction of the Commission and act accordingly. If the Company acts within the approved policies, its transactions will be conclusively prudent (Ex. A-4, at 7).

In his rebuttal testimony, Mr. Hutchens responded to Staff's concern that approval of the PSP in this case would put the Company on "autopilot" with respect to its procurement practices by indicating that such a practice would be inconsistent with the Company's past behavior and with the PSP itself (Ex. A-5 at 10). Mr. Pignatelli testified at the hearing that UNS sought the PSP approval in this case in order to avoid second-guessing during "the heat of a rate case three or four years after the fact" (Tr. at 106). He indicated that while the Company would keep adequate documentation of its procurement practices, he feared "a political decision down the road" (Tr. at 122).

Staff opposes the Company's request for approval of the PSP, arguing that approval of UNS Gas's hedging policy would insulate 45 percent of its gas purchases from a subsequent prudence review and is not necessary if the Company retains adequate documentation. Staff argues that UNS Gas and Staff have a fundamental disagreement regarding the purpose of the hedging plan. Staff claims that, as indicated by Mr. Hutchens, UNS views the hedging policy only as a means of reducing the volatility of natural gas prices (Tr. at 129, 157), whereas Staff believes that hedging policies ensure price stability, reliability, and competitiveness to achieve the lowest possible cost (Tr. at 744-45). Staff asserts that elimination of traditional prudence reviews in favor of the "compliance review" process sought by the Company would deprive Staff of the ability to properly employ its three-prong standard.

Staff witness Mendl also expressed concern with the higher burden of proof that would exist for Staff under the Company's proposal. He stated that if pre-approval of a particular plan is given, the Company may seek to abide by that plan instead of responding to market conditions, because adherence to the prior plan would be deemed presumptively reasonable (Tr. at 772). Staff argues that pre-approval is not necessary because, as pointed out by Mr. Mendl, prudence is judged based on what was known at the time decisions were made, not on a retrospective analysis (*Id.*). Staff contends that UNS can protect itself from future prudence disallowances by maintaining proper documentation regarding the decisions that were made and that the Company has not presented any evidence that the current standard is unfair.

We agree with Staff that the Company's request is simply unnecessary because there has been no evidence presented to suggest that the current process is unfair or unreasonable. Indeed, Mr. Hutchens conceded that there has been no indication that "there would be some unfair or biased after-the-fact analysis based on …[the] Staff recommendations" (Tr. at 140). Mr. Hutchens also admitted that the only benefits to be gained from granting UNS's request are to the Company and that the purpose of seeking the Commission's approval of the PSP is to insulate the Company from risk (Tr. at 778). As Staff indicates, UNS Gas can avoid future prudence disallowances by properly documenting its procurement practices and policies. Moreover, in spite of Mr. Pignatelli's cynical assertion that pre-approval is necessary to avoid politically based decisions in the future, the record suggests that just the opposite is true. As discussed above, two outside Staff consultants conducted a comprehensive audit of the Company's procurement practices from September 2003 through 2005 and found that UNS Gas's practices and policies were prudent. We agree with Staff's recommendations. We do not believe that UNS Gas has presented a sufficient justification for approval of the PSP, and we therefore deny its request.

Purchased Gas Adjustor

In Docket No. G-04204A-06-0013 (the PGA Case), which was previously consolidated in the above-captioned proceeding, UNS Gas filed an application seeking approval to revise its current Purchased Gas Adjustor ("PGA"). UNS witness Hutchens testified that the current volatile natural gas market has exposed weaknesses in the Company's existing PGA mechanism, which cause delays in cost recovery, and that such delays impact customer decisions based on the lack of timely price information and impact the Company's cash flows (Ex. A-4 at 7). Mr. Hutchens stated that the deficiencies in the current PGA include: 1) inappropriate price signals to customers, 2) the potential for large bank balances to accumulate 3) a below-market interest allowance earned on bank balances; 4) an inappropriately narrow bandwidth, and 5) a potentially adverse impact on the Company's ability to devote capital to necessary investments to serve customers (*Id.* at 7-8).

Based on these claimed deficiencies, Mr. Hutchens made the following recommendations in his direct testimony to improve the Company's PGA mechanism:

1. Bandwidth – The bandwidth should be eliminated or, in the alternative, increased to $0.25 per therm for an interim period of time and then eliminated.
2. Base Cost of Gas – The base cost of gas should be set at zero, and the entire cost of gas reflected in the PGA.
3. PGA Bank Interest – The interest earned on the PGA bank balance should reflect UNS Gas's actual cost of new debt, which is the London Inter-Bank Offering Rate ("LIBOR") plus 1.5 percent.
4. Bank Balance Thresholds – The new threshold level for under-collected bank balances established in Decision No. 68325 ($6,240,000) should also be adopted as the threshold level for over-collected bank balances.
5. Capital Structure – To the extent the PGA bank balances result in long-term financing, that debt should be excluded from the cost of capital calculation in rate case proceedings.
6. Surcharges – When surcharges are required, the Commission should approve a surcharge large enough to eliminate the bank balance in a reasonable time period and allow for timely recovery (*Id.* at 8).

In his direct testimony, Staff witness Robert Gray offered seven recommendations regarding the Company's PGA proposals. He stated as follows:

1. The base cost of gas should be set at zero.

2. UNS should provide specific customer education materials to explain the change (setting the cost to zero), and should represent the cost of gas as a specific and separate line item on customer bills, noting in a footnote any temporary PGA surcharge or credit in effect.
3. During the first 12 months the new PGA bandwidth is in effect, UNS should provide a comparison of the new monthly PGA rate to the sum of the base cost of gas and the monthly PGA rate in prior months.
4. The bandwidth on the monthly PGA rate should be expanded to $0.15 per therm.
5. The threshold on the PGA bank balance for *under-collected* balances should be eliminated.
6. The threshold on the PGA bank balance for *over-collected* balances should be set at $10 million.
7. The currently applicable interest rate for the PGA bank balance should be retained.

UNS claims that the parties are in agreement regarding most of the PGA issues. The Company points out that all parties agree that the entire cost of gas should be reflected in the PGA and that the base cost of gas should be set at zero in order to send proper price signals regarding the actual cost of gas. UNS also contends that all parties have agreed that some widening of the current bandwidth is appropriate, although Staff continues to disagree with the requested level of the widening. In his rebuttal testimony, Mr. Hutchens agreed with Staff's recommendation that the under-collection threshold for requesting a PGA surcharge should be eliminated and that the over-collection threshold should be set at $10 million (Ex. A-5 at 4). The two remaining disputed PGA issues are the appropriate bandwidth level and the PGA bank interest rate.

PGA Bank Interest Rate

UNS witness Hutchens testified that the Company is requesting that it be allowed to recover through the PGA one of two rates, depending on the size of the PGA bank balance. For balances below twice the PGA threshold (currently $6.24 million), UNS seeks to earn the interest rate based on LIBOR plus 1.0 percent.[17] For balances that exceed twice the PGA bank balance threshold, UNS seeks to recover a "carrying cost at a rate equal to UNS Gas' authorized rate weighted average cost of capital as determined in this proceeding" (Ex. A-4 at 14).[18]

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[17] UNS initially sought interest rate recovery based on LIBOR plus 1.5 percent, but amended the request to LIBOR plus 1.0 percent through Mr. Hutchens's rebuttal testimony, due to a lowering of the interest rate on the Company's short-term revolving credit facility (Ex. A-5 at 5).

[18] As discussed above, the WACC established in this proceeding is 8.30 percent, compared to the LIBOR plus 1.0 percent rate, which was 5.53 percent at the end of May 2007 (See Ex. A-4 at 13).

Although RUCO agreed to the LIBOR plus 1.5 percent rate (and would presumably also agree to the modified LIBOR plus 1.0 percent rate), RUCO opposes allowing the WACC rate to be applied to the higher balances requested by UNS (RUCO Ex. 5 at 24-25). RUCO contends that, given its agreement with the Company's proposal to double the current bandwidth and to provide for timely recovery of necessary surcharges, the higher interest rate would not be necessary because UNS would no longer be burdened with large under-collected balances. Ms. Diaz Cortez added that it would be inappropriate to predetermine outside of a rate case the ratemaking treatment to be afforded to the specific debt (*Id.* at 25-26).

Staff also opposes the Company's request to apply the WACC to higher PGA bank balances. Staff witness Robert Gray testified that interest rates for PGA bank balances were originally set in a generic docket (Decision No. 61225, issued October 30, 1998) and applied uniformly to all Arizona LDCs as a result of the consensus of a working group that included LDCs, Staff, and RUCO (Ex. S-41 at 13). The uniform interest established in that generic docket was the monthly three-month commercial *non-financial* paper rate, as established by the Federal Reserve (*Id.*). Mr. Gray stated that the interest rate was later changed in a subsequent generic proceeding (Decision No. 68600, issued March 23, 2006), only because the Federal Reserve was no longer publishing the previously established rate. Therefore, the current generic interest rate for PGA bank balances is the monthly three-month commercial *financial* paper rate published by the Federal Reserve. The rates are similar, although the current rate is slightly higher, on average, than the prior rate (*Id.*).

According to Mr. Gray, the Company's request should be rejected by the Commission for several reasons. He stated that the UNS proposal is unnecessary because it would add a level of administrative complexity to the process in making the calculations and because the PGA bank balances do not always trend upwards (*Id.* at 14). Mr. Gray testified that it was unclear which LIBOR rate the Company was proposing to use, that it appears the LIBOR itself would be very close to the interest rate currently in effect, and that it is only the application of an add-on component to the LIBOR rate (*i.e.*, the LIBOR plus 1.0 percent proposed by UNS) that raises the rate above the current rate by a substantial amount (*Id.* at 14-15). Mr. Gray indicated that the PGA interest rate approved recently for Southwest Gas was the one-year nominal Treasury constant maturities rate, which is comparable to the rate currently in effect for UNS Gas. The same rate is in effect for APS, and Mr. Gray asserts that UNS has not presented any justification for a different treatment (*Id.* at 15).

Mr. Gray also stated that Staff's recommendations to expand the PGA bandwidth (see discussion below) and to expand and eliminate the bank balance thresholds would reduce the likelihood of UNS Gas's incurring substantial bank balances for long periods of time (*Id.* at 16). He therefore recommended that the existing interest rate continue to be applied to UNS's PGA bank balances or, as an alternative, that the same interest rate applicable to both Southwest Gas and APS (the one-year nominal Treasury constant maturities rate) be applied (*Id.*). Finally, Mr. Gray recommended that if the applicable interest rate becomes unavailable (*i.e.*, unpublished) for one or more months, the prior month's interest rate apply. If the interest rate becomes unavailable on a recurrent basis, he recommends that UNS file a request to change to a comparable rate (*Id.* at 17).

We agree with Staff that UNS has not presented a sufficient basis for altering the PGA bank balance interest rate that currently exists. As Mr. Gray points out, a similar rate is in effect for Southwest Gas and APS, and we see no reason why UNS should be treated differently from those companies. In addition, granting a higher interest rate could provide a disincentive for the Company to reduce bank balances and could cause it to become less focused on taking all possible measures to reduce the cost of gas for its customers (*Id.* at 15-16). We therefore adopt Staff's recommendation to retain the current interest rate for UNS's PGA bank balances.

Expansion of Bandwidth

Under its current configuration, the Company's PGA bandwidth limits the movement of the monthly PGA rate over a 12-month period. The current bandwidth is $0.10 per therm, which means that when a new PGA rate is calculated each month, the new monthly rate cannot be more than $0.10 per therm different than the monthly PGA rate for any of the previous 12 months (Ex. S-41 at 5). Mr. Gray explained that the PGA bandwidth was initially established in 1999 at a rate of $0.07 per therm for Arizona LDCs during a period of relatively stable gas prices. As prices became more volatile, that bandwidth level often limited the movement of monthly PGA rates for periods of time. In Decision No. 62994 (November 3, 2000), UNS's predecessor was granted a bandwidth increase to $0.10 per therm (*Id.*). Mr. Gray testified that recent bandwidth adjustments were approved for

Southwest Gas (to $0.13 per therm) and for Duncan Rural (could change up to $1.20 per therm per year). However, he indicated that the Commission granted the significant expansion to Duncan Rural due to that company's small size and considerable financial constraints (*Id.* at 6).

In its application, UNS Gas initially requested that the PGA bandwidth be eliminated or, alternatively, set at $0.25 per therm for a period of time before being eventually eliminated (Ex. A-4 at 11-12). In his rebuttal testimony, UNS witness Hutchens agreed with RUCO's proposal to increase the current bandwidth to $0.20 per therm (Ex. A-5 at 3-4). Mr. Hutchens stated that setting the bandwidth at an inappropriately low level would fail to send proper price signals to customers regarding the actual cost of the gas being consumed (Ex. A-4 at 12).

Staff witness Gray recommended that the bandwidth be increased to $0.15 per therm. He stated that this bandwidth increase would provide the Company with significant additional room for movement of the monthly PGA rate, while providing a reasonable limit on the exposure of UNS customers to automatic adjustments without Commission review. Mr. Gray also indicated that Staff remains open to consideration of further changes to the PGA mechanism, if such changes are warranted (Ex. S-41 at 7-8). He explained in his surrebuttal testimony that setting a proper bandwidth level requires a balancing of several policy goals, including "timely recovery of gas costs by the utility, reduction of price volatility for ratepayers, and the Commission's interest in reviewing significant changes in rates before they are passed along to ratepayers." (Ex. S-42, at 2) He conceded that employing a bandwidth could result in the Company's accumulating large bank balances that must eventually be paid by customers (Tr. at 1133). However, he reiterated that the various policy goals, including protection of ratepayer interests, must be balanced in setting the bandwidth (*Id.*).

We agree with Staff's recommendations regarding the PGA issues, including increasing the Company's bandwidth to $0.15 per therm. The $0.15 per therm bandwidth is higher than the $0.13 bandwidth approved recently for Southwest Gas, and we believe it is reasonable under the facts of this case. Although UNS attempts to use the Duncan Rural case as a basis for seeking a greater increase in the bandwidth, Mr. Gray explained that Duncan is a very small natural gas cooperative with only 80 customers and that it has significant financial issues. UNS Gas is not in a comparable situation, and we do not believe a comparison with Duncan Rural is relevant for purposes of setting an appropriate bandwidth in this proceeding. Indeed, the 50 percent increase over UNS's current bandwidth is significant and properly balances the policy goals identified in Staff's testimony. The rate of $0.15 per therm will provide UNS Gas with a greater degree of flexibility in maintaining its PGA bank balances at a reasonable level, while also offering to customers a measure of protection from sudden automatic PGA increases outside of the Commission's purview.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. On November 10, 2005, the Arizona Corporation Commission opened an inquiry (Docket No. G-04204A-05-0831) into the prudence of the gas procurement policies and practices of UNS Gas Inc. (the Prudence Case).

2. On January 10, 2006, UNS Gas filed an application (Docket No. G-04204A-06-0013) with the Commission seeking review and revision of the Company's Purchased Gas Adjustor (the PGA Case).

3. On July 13, 2006, UNS Gas filed an application with the Commission (Docket No. G-04204A-06-0463) for an increase in its rates throughout the State of Arizona (the Rate Case).

4. On August 14, 2006, Staff filed a Letter of Sufficiency indicating that the Company's Rate Case application met the sufficiency requirements outlined in A.A.C. R14-2-103 and classifying the Company as a Class A utility.

5. On September 8, 2006, a Procedural Order was issued consolidating the Prudence Case, PGA Case, and Rate Case dockets; scheduling a hearing for April 16, 2007; and setting various other procedural deadlines.

6. Intervention was granted to RUCO, ACAA, and Marshall Magruder.

7. With its application in the Rate Case, UNS filed its required schedules in support of the application, and the direct testimony of various witnesses.

8. On February 9, 2007, Staff, RUCO, ACAA, and Mr. Magruder filed direct testimony in accordance with the previously established procedural schedule. Staff filed additional direct

testimony on February 16 and February 23, 2007.

9. On March 16, 2007, UNS filed the rebuttal testimony of various witnesses in response to Staff and intervenor testimony.

10. Surrebuttal testimony was filed by ACAA on March 30, 2007; and by Staff, RUCO, and Mr. Magruder on April 4, 2007.

11. On April 11, 2007, UNS filed the rejoinder testimony of several witnesses in response to the surrebuttal testimony of Staff and intervenor witnesses.

12. The evidentiary hearing commenced as scheduled on April 16, 2007, and additional hearing days were held on April 17, 18, 19, 20, 24, and 25, 2007.

13. Initial Post-Hearing Briefs were filed on June 5, 2007, by UNS, Staff, RUCO, and Mr. Magruder. Final Schedules were also filed on June 5, 2007, by UNS and RUCO. On June 6, 2007, Staff filed a Notice of Errata and revised Initial Brief.

14. Reply Briefs were filed on June 19, 2007, by UNS, Staff, RUCO, and Mr. Magruder.

15. On June 21, 2007, Staff filed a Notice of Errata and Additional Authority.

16. According to the Company's application, as modified, in the test year ended December 31, 2005, UNS had adjusted operating income of $8,506,168 on an adjusted OCRB of $162,358,856, for a 5.24 percent rate of return.

17. UNS requests a revenue increase of $9,459,023, Staff recommends a revenue increase of $4,312,354, and RUCO recommends a revenue increase of $2,734,443.

18. For purposes of this proceeding, we determine that UNS Gas has an OCRB of $154,604,408 and a FVRB of $184,120,761.

19. A rate of return on FVRB of 6.97 percent is reasonable and appropriate.

20. The Company's attempt to interject the issue of the *Chaparral City* decision through its rebuttal testimony was untimely, prejudicial to the other parties, and its late attempt to apply the weighted average cost of capital to FVRB is not reasonable and is not supported by the testimony and evidence in the record.

21. UNS Gas is entitled to a gross revenue increase of $5,257,468.

22. The Company's proposed decoupling mechanism proposal, the Throughput

Adjustment Mechanism, is not adopted in this proceeding.

23. The class responsibility for the revenue requirement should be allocated using the methodology of Staff's rate design expert witness.

24. For residential customers under Schedule R10, the basic monthly customer charge should be increased from $7.00 to $8.50, with a commodity charge increase to $0.3270 per therm, based on the revenue requirement established herein.

25. For CARES customers (Schedule R12), the current customer charge of $7.00 should remain in place, with a commodity charge increase to $0.3270 per therm, based on the revenue requirement established herein.

26. The rates for other customer classes should be set based on Staff's rate design recommendation, with the customer charges for each class established at the level recommended by Staff and with volumetric charges based on the revenue requirement determined herein.

27. The billing determinants proposed by the Company should be employed for setting rates in this proceeding.

28. Staff's recommendation to set the DSM adjustor surcharge at an initial level of $0.0025, which reflects exclusion of the baseline cost study, is reasonable. In addition, it is reasonable to require UNS to file semi-annual reports for the DSM programs, to shift the adjustor filing date to April 1 (with an Adjustor date of June 1), and that the appropriate forum for a full review of the specific DSM programs is in the separate docket in which there is an application currently pending.

29. In the event that UNS Gas does not currently have in place a bill statement contribution option, the Company should implement the change within 60 days of the effective date of this Decision.

30. The Company's natural gas procurement practices and policies during the audit period of September 2003 through December 2005 are deemed prudent.

31. UNS Gas has not presented a sufficient justification for approval of the Price Stabilization Plan.

32. With respect to the Company's Purchased Gas Adjustor mechanism, we adopt Staff's

recommendations, including setting the base cost of gas at zero and increasing the current $0.10 per therm adjustment band to $0.15 per therm.

33. The interest rate for the Company's PGA bank balance should remain in place (monthly three-month commercial financial paper rate published by the Federal Reserve), in accordance with Staff's recommendation.

34. DSM programs should be funded at the level recommended by Staff: LIW funding ($113,400) and 25 percent of the new program costs ($229,154) should be included in the initial DSM surcharge, but UNS Gas's portion of the baseline study costs ($82,000) should not be included in the surcharge initially. Staff's proposed initial DSM surcharge of $0.0025 is therefore adopted.

35. With respect to the use of payday loan stores for acceptance of customer payments, the Company should make every reasonable effort to determine whether other payment locations may be utilized either in addition to, or in lieu of, the payday loan stores currently used by UNS, and the Company should file a copy of its recommendations consistent with this directive within 90 days of the effective date of this Decision.

36. The Company's line and main extension proposals are a reasonable means of increasing the up-front contributions required from new customers and developers to connect to the UNS Gas system, subject to inclusion of the addition of a charge for excess flow valve installation, and subject to the additional requirement that UNS Gas investigate fully the issue of developer contributions and present in its next rate case viable alternatives to the proposal adopted herein, including but not limited to nonrefundable hook-up fees and other measures that would hold harmless existing customers and require greater contributions to ensure that growth pays for itself.

37. UNS Gas's proposed billing change, to reduce from 15 days to 10 days, the date for customers to pay bills before the bills are considered past due, is a reasonable modification that will make the Company's tariffs consistent with the Commission's Rules and would remove an inconsistency among the billing tariffs currently in effect for the other UniSource affiliates. However, in accordance with the Company's agreement to abide by Staff's six-month waiver recommendation, UNS Gas should not implement the approved billing change for at least six months following the effective date of this Decision.

CONCLUSIONS OF LAW

1. UNS Gas is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§40-250, 40-251, and 40-367.

2. The Commission has jurisdiction over UNS Gas and the subject matter of the above-captioned Rate Case, Prudence Case, and PGA Case.

3. The fair value of UNS Gas's rate base is $184,120,761, and applying a 6.97 percent rate of return on this fair value rate base produces rates and charges that are just and reasonable.

4. The rates, charges, approvals, and conditions of service established herein are just and reasonable and in the public interest.

ORDER

IT IS THEREFORE ORDERED that UNS Gas, Inc., is hereby authorized and directed to file with the Commission, on or before November 30, 2007, revised schedules of rates and charges consistent with the discussion herein and a proof of revenues showing that, based on the adjusted test year level of sales, the revised rates will produce no more than the authorized increase in gross revenues.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after December 1, 2007.

IT IS FURTHER ORDERED that UNS Gas, Inc., shall notify its customers of the revised schedules of rates and charges authorized herein by means of an insert, in a form acceptable to Staff, included in its next regularly scheduled billing,.

IT IS FURTHER ORDERED that UNS Gas, Inc., shall file in its next rate case more detailed support for allowance of AGA dues and an explanation of how the AGA's activities, aside from marketing and lobbying efforts, benefit the Company's customers.

IT IS FURTHER ORDERED that UNS Gas, Inc., should engage in discussions with other stakeholders affected by this issue, participate in the ongoing DSM workshops before the Commission, and, if possible, attempt to develop a decoupling mechanism that does not suffer from the types of deficiencies identified by the parties in this case.

IT IS FURTHER ORDERED that if UNS Gas, Inc., does not currently have in place a bill statement contribution option, it shall implement such a change within 60 days of the effective date of this Decision.

IT IS FURTHER ORDERED that UNS Gas, Inc., shall set the DSM adjustor surcharge at an initial level of $0.0025, and shall make its DSM adjustor filing by April 1 of each year.

IT IS FURTHER ORDERED that UNS Gas, Inc., shall file semi-annual reports for its DSM programs in accordance with Staff's recommendations.

IT IS FURTHER ORDERED that UNS Gas, Inc., shall file a copy of its recommendations regarding available alternatives for payment and service center locations within 90 days of the effective date of this Decision.

IT IS FURTHER ORDERED that UNS Gas, Inc. shall submit, within 30 days of this Decision, a revised Excess Flow Valve Installation tariff indicating that all new customers/developers shall pay the full cost of installation and the payment shall be a contribution (i.e. non-refundable).

IT IS FURTHER ORDERED that UNS Gas, Inc., shall investigate fully the issue of developer contributions and present in its next rate case viable alternatives to the proposal adopted herein, including but not limited to nonrefundable hook-up fees and other measures that would hold harmless existing customers and require greater contributions to ensure that growth pays for itself.

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IT IS FURTHER ORDERED that UNS Gas, Inc., shall not implement the approved billing change to reduce the payment due date, for six months following the effective date of this Decision.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN | COMMISSIONER

COMMISSIONER | COMMISSIONER | COMMISSIONER

IN WITNESS WHEREOF, I, DEAN S. MILLER, Interim Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 27th day of Nov., 2007.

DEAN S. MILLER
INTERIM EXECUTIVE DIRECTOR

DISSENT ______________

DISSENT ______________

SERVICE LIST FOR: UNS GAS, INC.

DOCKET NOS.: G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831

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BEFORE THE ARIZONA CORPORATION CC

COMMISSIONERS

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

Arizona Corporation Commission
DOCKETED
JUN 28 2007
DOCKETED BY nl

EXHIBIT
RUCO-9
ADMITTED

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827 DECISION NO. 69663 **OPINION AND ORDER**

DATES OF HEARING:	October 5, (Pre-Hearing Conference), December 6, (Procedural Conference), October 10, 11, 12, 13, 16, 19, 20, 23, 24, 25, 26, 30, November 3, 6, 7, 8, 9, 20, 27, 28, 30, December 1, 4, 5, 6, 11, 12, 13, and 15, 2006.
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Lyn Farmer
IN ATTENDANCE:	Jeff Hatch-Miller, Chairman Mike Gleason, Commissioner Kristin K. Mayes, Commissioner William A. Mundell, Commissioner Barry Wong, Commissioner
APPEARANCES:	Mr. Thomas L. Mumaw, PINNACLE WEST CAPITAL CORPORATION, Ms. Deborah R. Scott, SNELL & WILMER, LLP, and Mr. William Maledon, OSBORN MALEDON, P.A., on behalf of Arizona Public Service

Company;

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

Mr. Bill Murphy, MURPHY CONSULTING, on behalf of Distributed Energy Association of Arizona;

Ms. Laura Sixkiller, ROSHKA, DeWULF & PATTEN, PLC, on behalf of UniSource Energy Services;

Mr. Timothy Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, on behalf of Southwest Energy Efficiency Project and Western Resource Advocates;

Mr. Gary L. Nakarado, on behalf of Vote Solar and Arizona Solar Energy Industry;

Mr. Michael Grant, GALLAGHER & KENNEDY, P.A., on behalf of Arizona Utility Investors Association;

Mr. Kurt J. Boehm, BOEHM, JURTZ & LOWRY, on behalf of the Kroger Company;

Mr. C. Webb Crockett, FENNEMORE CRAIG, P.C., on behalf of the Arizonans for Electric Choice and Competition and Phelps Dodge Mining Company;

Lieutenant Colonel Karen S. White, on behalf of the Federal Executive Agencies;

Mr. Jay I. Moyes, MOYES STOREY, on behalf of Az-Ag Group;

Mr. Andrew W. Bettwy, on behalf of Southwest Gas Corporation;

Mr. Douglas V. Fant, on behalf of the Interwest Energy Alliance and Distributed Energy Association of Arizona;

Mr. Lawrence V. Robertson, Jr., MUNGER CHADWICK, on behalf of Southwestern Power Group II, LLC, Bowie Power Station, LLC and Mesquite Power, LLC.

Mr. Christopher Kempley, Chief Counsel, Ms. Janet F. Wagner, Senior Staff Attorney, and Mr. Charles Hains, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

We agree with Staff that it is disturbing that APS was not complying with USOA in recording its lobbying costs. When APS is concerned about timely recovery of its costs, and the time necessary to process its rate cases, it certainly does not speed up the process or instill confidence in APS' filings when the Commission learns that Staff auditors must expend extra time and effort to make sure all costs have been appropriately accounted for by the Company. Although APS now says that it agrees with Staff that all future lobbying expenses should be recorded below-the-line and that any recovery should in the future be expressed as a pro forma adjustment, and that it has made this change to its accounting system on a going-forward basis, we will order the Company to comply and expect Staff and other parties to monitor the Company's continued compliance with this requirement.

We agree with RUCO's adjustment to reduce lobbying expense by $785,654. APS did demonstrate some customer benefits that resulted from its lobbying activities, and with the APS allocated below-the-line costs together with those excluded in the RUCO adjustment, we find that the remaining costs are reasonable. However, we agree with Staff that it is not desirable to have to distinguish between "good" and "bad" lobbying activities. To the extent that in future rate cases APS proposes pro forma adjustments to recover its below-the-line lobbying expenses, APS must provide the itemized lobbying costs associated with each benefit it alleges resulted from the specific lobbying activity. Accordingly, we will reduce operating expense by removing $785,654 of lobbying expenses.

l. Incentive Compensation

1. Stock-Based Incentive Compensation

APS requests $4.8 million in TY operating expense related to its employee stock incentive program, which it asserts is integral in attracting and retaining high quality management personnel. Staff recommended eliminating costs associated with APS' stock-based incentive plans, but allowing recovery of TY expenses for APS' cash-based incentive compensation, approximately $17.8 million. Staff recommends the costs of the stock-based incentive plan not be included in rates because that compensation program is driven by the financial performance of Pinnacle West Capital Corporation

("Pinnacle West"), rather than the operational performance of APS as a public utility.[26] Staff recommends the costs of the cash-based incentive plan be included in rates because the TY level of those costs was tied to performance measures that benefit APS' customers.

APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost.

We agree with Staff that APS' stock-based based incentive compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate. As testified to by Staff witness Dittmer and set out in Staff's Initial Brief, "[e]nhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. . . . For example, some maintenance can be temporarily deferred, thereby boosting earnings.. . . But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." (Staff Initial Brief, pp. 31-31) To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation. Accordingly, we will reduce operating expense by $4,487,657.[27]

2. Cash-Based Incentive Compensation

APS incurred approximately $17.8 million of cash-based (variable) incentive expense during

[26] "Awards are based on the Company's compound annual growth rate in Earnings Per Share over a three-year performance period relative to the S&P Electric Utilities Super Composite EPS growth rate over the same period." APS Exhibit No. 51, Gordon Rebuttal, p. 21.

[27] ACC Jurisdictional amount, Staff Initial Brief, Revised Joint Accounting Schedule, Schedule C-13.

the TY.[28] APS' variable incentive program is an "at risk" pay program where a part of an employee's annual cash compensation is put at risk and expectations are established for the employee at the start of the year. If certain performance results are achieved, a predictable award will be earned based upon objective criteria. The actual amount of the award depends upon the achieved results. The intent of the plan is to: link pay with business performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture. (APS Exhibit No. 51, Gordon Rebuttal, p. 8) Staff did not oppose inclusion of the TY variable incentive expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the TY level of expense is tied primarily to performance measures that directly benefit APS customers. (Staff Exhibit No. 43, Dittmer Direct, p. 110)

RUCO proposed an adjustment reducing APS' cash-based incentive program expense by approximately 20 percent, or $4,563,000. The adjustment is based on a policy recommendation that ratepayers should not be expected to shoulder the entire incentive program that allows APS employees to earn additional compensation when APS ratepayers have experienced repeated rate increases over the past two years. APS opposes RUCO's adjustment as arbitrary and without analysis or justification. In its Reply Brief, RUCO indicates that it is not recommending adoption of both the RUCO and the Staff adjustment to incentive pay, and that Commission adoption of either one would be appropriate. We adopted the Staff adjustment for the reasons set forth above, and believe that adjustment will reflect an appropriate level of incentive compensation. Therefore we will not adopt RUCO's adjustment.

2. Uncontested Operating Adjustments

a. Spent Fuel Storage

No party has disputed APS' final adjustment to increase purchased power and fuel costs by $10,653,000 to reflect the Company's ongoing ACC Jurisdictional costs for interim storage of spent

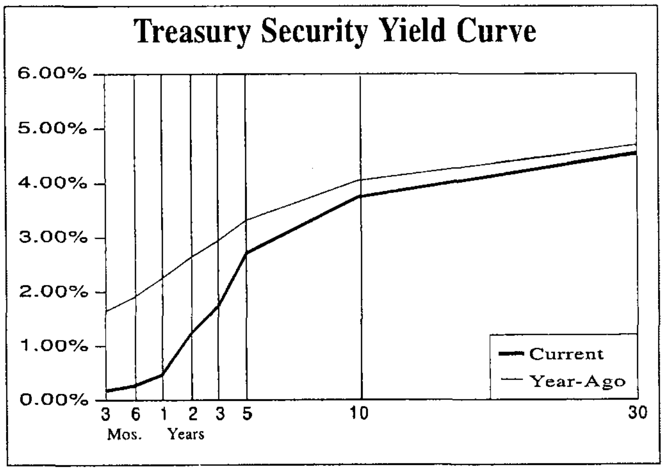
[28] Total expense was $21,727,033, but the Company voluntarily eliminated Officers' cash-based compensation in the amount of $3,895,147, leaving $17,831,886 in the proposed TY cost of service. Staff Exhibit S-34, Dittmer Direct p. 107, footnote 31.

EXHIBIT
RUCO-10
ADMITTED

Selected Yields

	Recent (8/05/09)	3 Months Ago (5/06/09)	Year Ago (8/06/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.28	0.40	2.79
3-month LIBOR	0.47	0.97	2.80
Bank CDs			
6-month	0.50	0.79	1.59
1-year	0.73	0.98	2.26
5-year	1.90	1.93	4.16
U.S. Treasury Securities			
3-month	0.18	0.18	1.65
6-month	0.27	0.31	1.91
1-year	0.47	0.50	2.26
5-year	2.72	2.05	3.32
10-year	3.75	3.16	4.05
10-year (inflation-protected)	1.82	1.69	1.73
30-year	4.55	4.10	4.70
30-year Zero	4.65	4.14	4.75

	Recent (8/05/09)	3 Months Ago (5/06/09)	Year Ago (8/06/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.74	3.37	5.85
FHLMC 6.5% (Gold)	3.13	2.91	5.89
FNMA 6.5%	2.91	2.71	5.79
FNMA ARM	2.75	2.78	4.03
Corporate Bonds			
Financial (10-year) A	6.85	7.19	6.34
Industrial (25/30-year) A	5.96	6.31	6.42
Utility (25/30-year) A	5.70	6.10	6.37
Utility (25/30-year) Baa/BBB	6.70	7.54	6.86
Foreign Bonds (10-Year)			
Canada	3.58	3.07	3.70
Germany	3.34	3.24	4.34
Japan	1.44	1.41	1.53
United Kingdom	3.83	3.61	4.75
Preferred Stocks			
Utility A	6.04	6.00	6.26
Financial A	7.47	8.19	6.94
Financial Adjustable A	5.51	5.51	5.51



	Recent (8/05/09)	3 Months Ago (5/06/09)	Year Ago (8/06/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.69	4.70	4.77
25-Bond Index (Revs)	5.66	5.57	5.23
General Obligation Bonds (GOs)			
1-year Aaa	0.42	0.43	1.52
1-year A	0.92	1.16	1.62
5-year Aaa	1.72	1.84	3.08
5-year A	2.16	3.25	3.18
10-year Aaa	2.99	2.91	3.82
10-year A	3.35	4.45	4.02
25/30-year Aaa	4.69	4.53	4.78
25/30-year A	5.15	6.05	5.13
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.65	6.10	4.90
Electric AA	5.75	6.15	4.85
Housing AA	5.90	6.45	5.15
Hospital AA	6.00	6.40	5.25
Toll Road Aaa	5.70	6.20	4.85

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	7/29/09	**7/15/09**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	728843	743861	-15018	777895	755939	557494
Borrowed Reserves	347217	387829	-40612	451108	519244	495733
Net Free/Borrowed Reserves	381626	356032	25594	326786	236695	61760

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	7/20/09	**7/13/09**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1644.8	1657.6	-12.8	23.5%	12.5%	16.7%
M2 (M1+savings+small time deposits)	8342.7	8333.8	8.9	4.0%	2.2%	7.8%

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
Kristen K. Mayes – Chairman
Gary Pierce
Sandra D. Kennedy
Paul Newman
Bob Stump

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	**) DOCKET No. G-04204A-08-0571**

DIRECT TESTIMONY

OF

FRANK W. RADIGAN

ON BEHALF OF
RESIDENTIAL UTLITIY CONUSMER OFFICE OF ARIZONA

Phoenix, Arizona
June 8, 2009

DIRECT TESTIMONY OF FRANK W. RADIGAN
EXECUTIVE SUMMARY

1) The Company's proposed cost of service study uses a Commission accepted method to allocate costs. The Company has proposed to allocate costs on an across the board basis except for the CARES customers who receive no increase. In these uncertain economic times an equal sharing of the rate increase is reasonable. The proposed revenue allocation is shown on Exhibit 3 and summarized below:

Class of Service	Present Revenue	Proposed Revenue	Proposed Increase	Proposed Percent Increase
Residential Service	$36,600,943	$37,190,974	$590,030	1.6%
Commercial Gas Service	$9,910,680	$10,076,399	$165,720	1.7%
Industrial Gas Service	$246,712	$250,838	$4,125	1.7%
Public Authority Gas Servic	$1,778,118	$1,807,850	$29,732	1.7%
Special Gas Light Service	$66,940	$68,059	$1,119	1.7%
Irrigation Service	$33,865	$34,431	$566	1.7%
Transportation Customers	$3,036,509	$3,086,270	$49,761	1.6%
Total	$51,673,767	$52,514,821	$841,054	1.6%

2) The Company's proposal not to increase the rates for the CARES customers is reasonable and abides by recent Commission treatment to these customers of holding them harmless from rate increase.

3) The Company's proposed rate design that would phase in a 71% increase in the residential customer charge over three years should be rejected. Instead, the proposed increase in the customer charges for what the Company describes as Year 1 are reasonable as they increase

rates towards the indicated cost of service but do not overly increase rates. My proposed customer charges are summarized in the table below.

	Present	Proposed	Increase	% Increase
Residential	$ 8.50	$ 10.00	$ 1.50	18%
Small Commercial & Industrial	13.50	15.50	2.00	15%
Large Commerical and Industrial	100.00	105.00	5.00	5%
Irrigation Service	13.50	15.50	2.00	15%

4) The impact for a Residential Customer from this proposed revenue allocation and rate design is as follows. The customer charge is proposed to increase from $8.50 per month to $10 per month and the commodity charge is proposed to decrease slightly from $0.3270 per therm to $0.3027 per therm. The average bill for the Residential Class is 45 therms per month and a customer with such average usage will see an increase of 1.7%, which is the class average increase. Detailed bill impacts from each class are shown on Schedule H-4 of Exhibit 3 to my testimony.

and joined the firm of Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own Company.

In my 27 years of experience, I have testified as an expert witness in utility rate proceedings on more than 80 occasions before various utility regulatory bodies including the Arizona Corporation Commission, the Connecticut Department of Utility Control, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Michigan Public Service Commission, the New York State Public Service Commission, the New York State Department of Taxation and Finance, the Nevada Public Utilities Commission, the Public Utilities Commission of Ohio, the Rhode Island Public Utilities Commission, the Vermont Public Service Board, and the Federal Energy Regulatory Commission.

I currently advise a variety of Regulatory Commissions, consumer advocates, municipal utilities and industrial customers concerning rate matters, including wholesale electricity rates and electric transmission rates. A summary of my qualifications and experience is included as Exhibit 1.

Q. **On whose behalf are you appearing?**

A. I am appearing on behalf of the Residential Utility Consumer Office of Arizona ("RUCO").

Q. **Have you previously testified before the Arizona Corporation Commission?**

A. Yes. I have testified before the Commission previously on four occasions. I testified before the Commission in the most recent UNS Electric, Inc. rate case (Docket No. E-04204A-06-0783), the most recent Tucson Electric Power Company rate case (Docket No. E-01933A-07-0402), the most recent Southwest Gas Company rate case (Docket No. G-01551A-07-0504) and the most recent Arizona Public Service Company rate case (Docket No. E-01345A-08-0172).

Q. What is the purpose of the testimony you are presenting?

A. I have been asked to discuss the reasonableness of UNS Gas, Inc.'s (UNS or the Company) proposed cost of service allocation and rate design.

Q. Could you please summarize your testimony?

A. Yes, based on my review of the filing I have the following conclusions and recommendations:

1) The Company's proposed cost of service study uses a Commission accepted method to allocate costs. The Company has proposed to allocate costs on an across the board basis except for the CARES customers who receive no increase. In these uncertain economic times an equal sharing of the rate increase is reasonable.

2) The Company's proposed rate design that would phase in a 71% increase in the residential customer charge over three years should be rejected. Instead, the proposed increase in the customer charges for what the Company describes as Year 1 are reasonable as they increase rates towards the indicated cost of service but do not overly increase rates.

I. INTRODUCTION

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

A. Frank W. Radigan. I am a principal in the Hudson River Energy Company, a consulting firm providing services to the utility industry and specializing in the fields of rates, planning, and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203.

Q. Would you please summarize your education and business experience?

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now Clarkson University) in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the Staff of the New York State Public Service Commission in the Rates and System Planning sections of the Power Division and in the Rates Section of the Energy and Water Division. My responsibilities included resource planning and the analysis of rates, depreciation rates and tariffs of electric, gas, water and steam utilities in the State and encompassed rate design and performing embedded and marginal cost of service studies as well as depreciation studies.

Before leaving the Commission, I was responsible for directing all engineering staff during major proceedings including those relating to rates, integrated resource planning and environmental impact studies. In February 1997, I left the Commission

3) The Company's proposal not to increase the rates for the CARES customers is reasonable and abides by recent Commission treatment to these customers of holding them harmless from rate increase.

Q. Could you please comment on the Company's cost of service study and revenue allocation?

A. Yes. The Cost of Service Study was prepared and presented by Company Witness Bentley Erdwurm and is described in his pre-filed testimony at pages 9-14. Mr. Erdwurm performed a traditional embedded cost of service study using the Proportional Responsibility method. This method uses the respective class' share of total load in each of the twelve months for the test-year to develop an allocation factor to assign costs. (Erdwurm PFT, page 17) The Proportional Responsibility method drives many significant costs in the class cost-of-service study model (Ibid). The Proportional Responsibility Method has been used in other recent rate case filings before the Commission including the Company's last rate case (Ibid). I have reviewed the allocation factors used in the study and the supporting data used to develop them. The results of the cost of service study are presented below:

UNS Gas, Inc.
Cost of Service Study Results

	Rate of Return	Indexed Rate of Return
Residential	5.6%	0.87
Total Commercial	11.5%	1.80
Total Industrical	1.4%	0.23
Total Public Authority	7.4%	1.16
Special Gas Light Service	32.3%	5.08
Irrigation	9.2%	1.44
Total Company	6.4%	1.00

Even though there is some disparity amongst classes in the indicated rates of return, the Company has proposed to allocate revenues on an across-the-board basis. Mr. Erdwurm argues that this allocation helps mitigate the adverse rate impact on any class (Erdwurm PFT, page 17). I agree and support his allocation.

Q. Could you please comment on the Company's proposed rate design?

A. Yes, as noted by Company Witness Erdwurm the Company's primary objectives in rate design is to more equitably collect its fixed costs (Erdwurm PFT page 18). UNS proposes an increase in monthly customer charges to levels that better match the true customer-related costs, as indicated by the class cost-of-service study (Ibid). As Mr. Erdwurm he is seeking to move the customer costs towards the "bare-bones" customer charge. "Bare-bones" customer charges restrict the customer classification to metering, meter-reading, service (service drop) to the specific customer, customer service and billing (Ibid). According to the study, the "bare bones" monthly customer charges are calculated to be $18.15 for residential service, approximately $19.00 for small commercial/industrial customers and approximately $220.00 for large commercial/industrial customers (Ibid).

Under Mr. Erdwurm's proposal for residential service, the increases will be phased-in over three years. Upon approval of this rate case the customer charge will increase from $8.50 per month to $10 per month. One year after rates are approved the customer charge will automatically increase from $10 to $12 per month and two years after rates are approved in this case the customer charge will automatically increase from $12 to $14 per month. Even after the three year phase in Mr. Erdwurm argues that the residential customer charge will still be below the "bare-bones" customer charge of $18.15. Customer charges for non-residential classes generally also are raised closer to levels indicated by the class cost-of-service study but there is no automatic phase in of cost increases. (Erdwurm PFT pages 18-19).

Q. Do you agree with Mr. Erdwurm's proposal on the Residential Customer Charge?

A. No. While the proposed customer charges are cost-based, the company has ignored the rate design principles of rate stability. Automatic rate increases are generally not appreciated by customers and this is especially true when it comes to rate increases that can be viewed as a large increase. Mr. Erdwurm's automatic rate increase in the second and third year will increase a small customer's bill by 40%. Outside of a rate case this large of an increase will undoubtedly cause an increase in customer complaints.

Q. Mr. Erdwurm argues that the very nature of UNS' service territory causes problems that must be addressed though the customer charge, can you comment on that?

A. Yes. In his testimony Mr. Erdwurm states given that natural gas usage is largely driven largely by weather, the Company's current rates have resulted in customers in cooler areas (i.e., districts with more heating degree days like Flagstaff) subsidizing those living in warmer areas (i.e., districts with less heating degree days like Lake Havasu City). He states that customers in the coldest corners of the service territory – those affected most by rising costs on the volumetric, gas commodity portion of their bills during home heating season – have borne the additional burden of subsidizing the fixed cost of serving customers who spend their winters in far more moderate climates (Erdwurm PFT pages 20 and 21). This argument is a red herring. Mr. Erdwurm's analysis only looks at the net margin from sales from small and large customers and notes that a large customer contributes more than a small. Large customers, however, also are served by large mains and can contribute more to peak indicating that it costs more to serve them. This can only be done through a cost of service study. If Mr. Erdwurm truly believes that UNS should have District rates, then he should present a study which actually studies if there are cost differences to serve the two Districts.

Q. Mr. Erdwurm argues that recovery of fixed costs in the customer charge as compared to the volumetric charge is preferred, do you disagree?

A. From the utility perspective that is true as they want to be able to recover most of their fixed costs up front. That said, however, in the rate case the Company's rates are designed to recover the total revenue requirement. Thus, the only risk to the Company is between rate cases if customer usage changes to due warmer than normal weather or customer conservation. On the other hand, there can be colder than average weather and customer growth can occur and this would help the Company. Thus, a balance must be reached that treats the Company and the customer fairly.

Q. What do you recommend be done with the customer charges?

A. A reasonable balance is one that recognizes 1) the customer cost indicated by the cost of service study, 2) rate stability for customers and 3) increasing the amount of money recovered though the fixed charge. To this end I recommend that the Company's proposed customer charge for year one allowed to become effective with no automatic increases allowed. Any further changes to the customer charge would be analyzed again in the next rate case. A summary of the present and proposed customer charges are presented in the table below.

	Present	Proposed	Increase	% Increase
Residential	$ 8.50	$ 10.00	$ 1.50	18%
Small Commercial & Industrial	13.50	15.50	2.00	15%
Large Commerical and Industrial	100.00	105.00	5.00	5%
Irrigation Service	13.50	15.50	2.00	15%

While the percentage increase appears relatively high given the RUCO is recommending a 1.6% overall increase, the dollar increases are low, however, with a residential customer's bill increase by only $1.50 per month. In addition, for each class the average customer receives a reasonable increase. For example, the average usage for a residential customer 45 therms per month and this customer will see an increase in their bill of 1.7% which is almost equal to the overall average increase being given to the Company of 1.6%.

Q. Please discuss the bill impact of your proposed rates for the Residential Class.

A. The customer charge is proposed to increase from $8.50 per month to $10 per month and the commodity charge is proposed to decrease slightly from $0.3270 per therm to $0.3027 per therm. The average bill for this class is 45 therms per month and a customer with such average usage will see an increase of 1.7% which is the class average increase. Typical bills for the full range of residential usage are included in Exhibit 3 (RUCO UNS Gas Schedule H, Schedule H-4, page 1).

Q. Please discuss the bill impact of your proposed rates for the Small Commercial Class (C-20).

A. The customer charge is proposed to increase from $13.50 per month to $15.50 per month and the commodity charge is proposed to decrease slightly from $0.2638 per therm to $0.2600 per therm. The average bill for this class is 214 therms per month, and a customer with that usage will see an increase of 1.7% which is the class average increase.

Q. Please discuss the bill impact of your proposed rates for the Large Volume Industrial (I-32).

A. The customer charge is proposed to increase from $100.50 per month to $105.00 per month and the commodity charge is proposed to increase slightly from $0.0952 per therm to $0.0966 per therm. The average bill for this class is approximately 20,000 therms per month, and a customer with that usage will see an increase of 1.7%, which is the class average increase.

Q. Please discuss the bill impact of your proposed rates for the CARES Residential Customers (R-12).

A. The Company has proposed to retain the CARES pricing plan, and proposes to hold the customer charge and the non-commodity volumetric charges at the current levels (Erdwurm PTF page 26). I agree this has been the adopted method in the recent TEP rate case and what staff proposed in the ongoing Arizona Public Service rate case. As shown on Exhibit 3, Schedule H-4, page 2, these customers will see no increase.

Q, Does this conclude your testimony?

A. Yes.

Exhibit 1
Resume of Frank W. Radigan

FRANK W. RADIGAN

EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present **Principal, Hudson River Energy Group, Albany, NY** – Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY** – Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** – Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Rate Case Cost of Service Study – Stowe Electric Department, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the Vermont Public Service Board. 2009

Rate Case Cost of Service Study – Village of Greene, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Bath, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Richmondville, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO

Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – **Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002**

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reduction control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 08-E-0539 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by $854 million. 2008

Docket No. 08-07-04 - United Illuminating - On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2008

Docket No. 08-06036 – Spring Creek Utilities - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the cost allocation and amortization of a new financial accounting system, the appropriate level of rate case expense, allocation of corporate salaries, recovery of property taxes, and rate design. 2008

D.P.U. 8-35 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the Company's request to increase rates in light of the terms of a previous settlement, the level of expenses being charged from the parent Company to the affiliate, the proposed increase in deprecation expense and the proposed revenue allocation and rate design. 2008

Docket No. 08-96 - Artesian Water Company - on behalf of the Staff of the Delaware Public Service Commission examined the reasonableness of the Company's cost of service study and proposed revenue allocation and rate design. 2008

Docket No. E-01345A-08-0172 - Arizona Public Service - on behalf of the on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposal regarding demand side management cost recovery. 2009

Docket No. 05-03-17PH02 – Southern Connecticut Gas Company – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded costs of service study and proposed revenue allocation and rate design. 2008

Docket No. 06-03-04PH02 – Connecticut Natural Gas Corporation – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study and proposed revenue allocation and rate design. 2008

Docket No. G-01551A-07-0504 – Southwest Gas Corporation – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding revenue decoupling. 2008

Docket No. E-01933A-07-0402 – Tucson Electric Power Company – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding mandatory time of use rates. 2008

Docket No. 07-09030 – Southwest Gas Corporation – on behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates. 2008

Civil Action 05-C-457-1 – Dominion Hope – on behalf of former employee of the utility examined the utility's hedging and sales for resale practices between affiliates. 2008

Case 07-829-GA-AIR – Dominion East Ohio – on behalf of the Office of the Ohio Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation and rate design and examined the reasonableness of proposals on revenue decoupling and straight fixed variable rate design. 2008

Case 07-S-1315 – Consolidated Edison Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2008

Case No. 9134 – Green Ridge Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case No. 9135 -- Provinces Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case 07-M-0906 – Energy East and Iberdola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over $1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission 2007

Docket No. 07-05-19 – Aquarion Water Company – On behalf of the Connecticut Office of Peoples Counsel examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design and its for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger, customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. 06-07-08 – Connecticut Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, revenue allocation and rate design. 2006

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission.

2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England. 2004

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed $0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

National Association of State Utility Consumer Advocates Annual Conference, 2008 – Speaker on a case study of "Smart Metering"

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association, Northeast Public Power Association and New York State ISO.

Exhibit 2
RUCO Proof of Revenues

Line No.	Class of Service	Billed BD (for Jul 2007 - Nov 2007	Billed BD (for Dec 2007 - Jun 2008	Total TY Unadjusted Billing Units	Rates as of Jul 2007 - Nov 2007	Existing Rates as of Dec 1, 2007	Current Unadjusted Billed Revenues	Allocation of Booked to Billed Revenue Difference	Unadjusted Revenues
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	H
				(A + B)			(A*D + B*E)	(F / Col. H, L.50)*Col. H, L.49	(F + G)
	Residential Service (R10)								
1	Customer Charge	625,116	882,107	1,507,223	$7.00	$8.50	$11,873,722		
2	Distribution Margin Therms	13,683,976	57,039,061	70,723,037	$0.3004	$0.3270	$22,762,439		
3	**TOTAL R10**						$34,636,161	$231,128	$34,867,289
	Residential Service Cares (R12)								
4	Customer Charge	32,616	48,322	80,938	$7.00	$7.00	$566,566		
5	Distribution Margin Therms - Summer	421,429	246,155	667,584	$0.3004	$0.3270	$207,090		
6	Distribution Margin Therms - Winter Non Discou	34,578	358,932	393,511	$0.3004	$0.3270	$127,758		
7	Distribution Margin Therms - Winter Discount	212,411	2,204,870	2,417,281	$0.1504	$0.1770	$422,209		
	TOTAL R12						$1,323,623	$8,833	$1,332,455
	Small Volume Commercial Service (C20)								
8	Customer Charge	56,440	80,641	137,081	$11.00	$13.50	$1,709,494		
9	Distribution Margin Therms	8,070,305	22,048,952	30,119,256	$0.2420	$0.2638	$7,769,527		
10	**TOTAL R20**						$9,479,021	$63,254	$9,542,274
	Large Volume Commercial Service (C22)								
11	Customer Charge	83	99	182	$85.00	$100.00	$16,955		
12	Distribution Margin Therms	473,791	968,787	1,442,578	$0.1551	$0.1718	$239,923		
13	**TOTAL R22**						$256,878	$1,714	$258,592
	Large Volume Commercial Transportation Service (C22)								
14	Customer Charge	65	60	125	$85.00	$100.00	$11,525		
15	Distribution Margin Therms	1,613,646	1,730,988	3,344,634	$0.1551	$0.1718	$547,660		
16	**TOTAL R22**						$559,185	$3,731	$562,917
	Small Volume Industrial Service (I-30)								
17	Customer Charge	76	136	212	$11.00	$13.50	$2,672		
18	Distribution Margin Therms	111,336	391,243	502,579	$0.2122	$0.2356	$115,802		
19	**TOTAL I30**						$118,474	$791	$119,265
	Large Volume Industrial Service (I-32)								
20	Customer Charge	31	37	68	$85.00	$100.00	$6,335		
21	Distribution Margin Therms	460,636	785,611	1,246,247	$0.0864	$0.0952	$114,589		
22	**TOTAL I32**						$120,924	$807	$121,731
	Large Volume Industrial Transportation Service (I-32)								
23	Customer Charge	50	91	141	$85.00	$100.00	$13,350		
24	Distribution Margin Therms	4,420,876	7,022,697	11,443,573	$0.0864	$0.0952	$1,050,524		
25	**TOTAL I32**						$1,063,874	$7,099	$1,070,974

UNS GAS, INC. CURRENT REVENUES
TEST PERIOD TME JUNE 30, 2008

Line No.	Class of Service	Billed BD (for Jul 2007 - Nov 2007	Billed BD (for Dec 2007 - Jun 2008	Total TY Unadjusted Billing Units	Rates as of Jul 2007 - Nov 2007	Existing Rates as of Dec 1, 2007	Current Unadjusted Billed Revenues	Allocation of Booked to Billed Revenue Difference	Unadjusted Revenues
	Small Volume Public Authority (PA-40)								
26	Customer Charge	5,288	7,459	12,747	$11.00	$13.50	$158,865		
27	Customer Charge - CNG	35	47	82	$30.00	$30.00	$2,460		
28	Distribution Margin Therms	960,064	4,837,614	5,797,679	$0.2351	$0.2593	$1,480,105		
29	**TOTAL PA40**						$1,641,429	$10,953	$1,652,382
	Large Volume Public Authority (PA-42)								
30	Customer Charge	25	35	60	$85.00	$100.00	$5,625		
31	Distribution Margin Therms	319,860	905,213	1,225,072	$0.1084	$0.1198	$143,117		
32	**TOTAL PA42**						$148,742	$993	$149,735
	Large Volume Public Authority Transportation Service (PA-42)								
33	Customer Charge	30	56	86	$85.00	$100.00	$8,150		
34	Distribution Margin Therms	1,309,069	3,818,141	5,127,210	$0.1084	$0.1198	$599,316		
35	**TOTAL PA42**						$607,466	$4,054	$611,520
	Special Gas Light Service (PA-44)								
36	Customer Charge Lighting Group A	45	63	108	$13.57	$15.17	$1,566		
37	Customer Charge Lighting Group B	1,495	2,093	3,588	$16.28	$18.20	$62,431		
38	**TOTAL PA44**	53,421	91,985	145,406			$63,998	$427	$64,425
	Irrigation Service (IR-60)								
39	Customer Charge	25	35	60	$11.00	$13.50	$748		
40	Distribution Margin Therms	88,197	16,069	104,267	$0.2876	$0.3192	$30,495		
41	**TOTAL IR60**						$31,242	$208	$31,451
	T1 Contract Customers								
42	Customer Charge	15	21	36	$85.00	$100.00	$3,375		
43	Distribution Margin Therms	1,668,664	5,895,627	7,564,291	$0.0867	$0.0867	$655,582		
44	**TOTAL IR60**						$658,957	$0	$658,957
	T2 - Customer								
45	Customer Charge	5	7	12	$85.00	$100.00	$1,125		
46	Distribution Margin Therms	311,964	839,169	1,151,133	$0.0544	$0.0544	$62,652		
47	**TOTAL IR60**						$63,777	$0	$63,777
48	**Customers**	**719,910**	**1,019,167**	**1,739,077**					
49	**Therms**	**34,214,222**	**109,201,115**	**143,415,337**					
50	**Revenue**						**$50,773,751**	**$333,992**	**$51,107,743**
50						Revenue Requirement Model	**$51,107,743**		
51						Difference	($333,992)		
52							**$333,992**		
							$50,051,018		

Valencia is charge a monthly Reservation Charge of $4,472.77
Rate per Therm of .0078

Line No.	Class of Service	Total TY Unadjusted Billing Units	Existing Rates as of Dec 1, 2007	Unadjusted Revenues	Revenue Annualization	Revenue Annualization Adjustment
	Residential Service (R10)					
1	Customer Charge	1,507,223	$8.50		$12,811,396	
2	Distribution Margin Therms	70,723,037	$0.3270		$23,126,433	
3	**TOTAL R10**			$34,867,289	$35,937,829	$1,070,540
	Residential Service Cares (R12)					
4	Customer Charge	80,938	$7.00		$566,566	
5	Distribution Margin Therms - Summer	667,584	$0.3270		$218,300	
6	Distribution Margin Therms - Winter	393,511	$0.3270		$128,678	
7	Distribution Margin Therms - Winter	2,417,281	$0.1770		$427,859	
	TOTAL R12			$1,332,455	$1,341,403	$8,947
	Small Volume Commercial Service (C20)					
8	Customer Charge	137,081	$13.50		$1,850,594	
9	Distribution Margin Therms	30,119,256	$0.2638		$7,945,460	
10	**TOTAL R20**			$9,542,274	$9,796,053	$253,779
	Large Volume Commercial Service (C22)					
11	Customer Charge	182	$100.00		$18,200	
12	Distribution Margin Therms	1,442,578	$0.1718		$247,835	
13	**TOTAL R22**			$258,592	$266,035	$7,443
	Large Volume Commercial Transportation Service					
14	Customer Charge	125	$100.00		$12,500	
15	Distribution Margin Therms	3,344,634	$0.1718		$574,608	
16	**TOTAL R22**			$562,917	$587,108	$24,191
	Small Volume Industrial Service (I-30)					
16	Customer Charge	212	$13.50		$2,862	
17	Distribution Margin Therms	502,579	$0.2356		$118,408	
18	**TOTAL I30**			$119,265	$121,270	$2,005
	Large Volume Industrial Service (I-32)					
19	Customer Charge	68	$100.00		$6,800	
20	Distribution Margin Therms	1,246,247	$0.0952		$118,643	
21	**TOTAL I32**			$121,731	$125,443	$3,712
	Large Volume Industrial Transportation Service					
22	Customer Charge	141	$100.00		$14,100	
23	Distribution Margin Therms	11,443,573	$0.0952		$1,089,428	
24	**TOTAL I32**			$1,070,974	$1,103,528	$32,554
	Small Volume Public Authority (PA-40)					
25	Customer Charge	12,747	$13.50		$172,085	
26	Customer Charge - CNG	82	$30.00		$2,460	
27	Distribution Margin Therms	5,797,679	$0.2593		$1,503,338	
28	**TOTAL PA40**			$1,652,382	$1,677,883	$25,500
	Large Volume Public Authority (PA-42)					
29	Customer Charge	60	$100.00		$6,000	
30	Distribution Margin Therms	1,225,072	$0.1198		$146,764	
31	**TOTAL PA42**			$149,735	$152,764	$3,029

Line No.	Class of Service	Total TY Unadjusted Billing Units	Existing Rates as of Dec 1, 2007	Unadjusted Revenues	Revenue Annualization	Revenue Annualization Adjustment
	Large Volume Public Authority Transportation Service					
32	Customer Charge	86	$100.00		$8,600	
33	Distribution Margin Therms	5,127,210	$0.1198		$614,240	
34	**TOTAL PA42**			$611,520	$622,840	$11,320
	Special Gas Light Service (PA-44)					
35	Customer Charge Lighting Group A	108	$15.17		$1,638	
36	Customer Charge Lighting Group B	3,588	$18.20		$65,302	
37	**TOTAL PA44**	145,406		$64,425	$66,940	$2,515
	Irrigation Service (IR-60)					
38	Customer Charge	60	$13.50		$810	
39	Distribution Margin Therms	104,267	$0.3192		$33,282	
40	**TOTAL IR60**			$31,451	$34,092	$2,641
	T1 Contract Customers					
41	Customer Charge	36	$100.00		$3,600	
42	Distribution Margin Therms	7,564,291	$0.0867		$655,582	
43	**TOTAL IR60**			$658,957	$659,182	$225
	T2 - Customer					
44	Customer Charge	12	$100.00		$1,200	
45	Distribution Margin Therms	1,151,133	$0.0544		$62,652	
46	**TOTAL IR60**			$63,777	$63,852	$75
47	**Customers**	**1,739,077**				
48	**Therms**	**140,998,057**				
49	**Revenue**			**$51,107,743**	**$52,556,220**	**$1,448,476**

UNS GAS, INC. PROOF OF ADJUSTED REVENUES
TEST PERIOD TME JUNE 30, 2008

Line No.	Class of Service	Total TY Unadjusted Billing Units	Existing Rates as of Dec 1, 2007	Unadjusted Revenues	Revenue Annualization	Revenue Annualization Adjustment	UNSG Adj. for Customer Annualizaton	UNSG Adj. for Weather Normalization	Adjusted Billing units	TY Adjusted Revenues	Total Customer & Weather Revenue Adjustment
	Residential Service (R10)										
1	Customer Charge	1,507,223	$8.50		$12,811,396		0		1,507,223	$12,811,396	
2	Distribution Margin Therms	70,723,037	$0.3270		$23,126,433		0	(1,993,041)	68,729,996	$22,474,709	
3	TOTAL R10			$34,867,289	$35,937,829	$1,070,540				$35,286,104	$651,725
	Residential Service Cares (R12)										
4	Customer Charge	80,938	$7.00		$566,566		0		80,938	$566,566	
5	Distribution Margin Therms - Summer	667,584	$0.3270		$218,300		0	(52,587)	614,997	$201,104	
6	Distribution Margin Therms - Winter	393,511	$0.3270		$128,678		0	(6,624)	386,887	$126,512	
7	Distribution Margin Therms - Winter	2,417,281	$0.1770		$427,859		0	(40,688)	2,376,593	$420,657	
	TOTAL R12			$1,332,455	$1,341,403	$8,947			3,378,478	$1,314,839	$26,564
	Small Volume Commercial Service (C20)										
8	Customer Charge	137,081	$13.50		$1,850,594		0		137,081	$1,850,594	
9	Distribution Margin Therms	30,119,256	$0.2638		$7,945,460		0	(557,223)	29,562,033	$7,798,464	
10	TOTAL R20			$9,542,274	$9,796,053	$253,779				$9,649,058	$146,996
	Large Volume Commercial Service (C22)										
11	Customer Charge	182	$100.00		$18,200		0		182	$18,200	
12	Distribution Margin Therms	1,442,578	$0.1718		$247,835		0	(25,886)	1,416,892	$243,422	
13	TOTAL R22			$258,592	$266,035	$7,443				$261,622	$4,413
	Large Volume Commercial Transportation Service (C22)										
14	Customer Charge	125	$100.00		$12,500		0		125	$12,500	
15	Distribution Margin Therms	3,344,634	$0.1718		$574,608		0	0	3,344,634	$574,608	
16	TOTAL R22			$562,917	$587,108	$24,191				$587,108	$0
	Small Volume Industrial Service (I-30)										
16	Customer Charge	212	$13.50		$2,862		0		212	$2,862	
17	Distribution Margin Therms	502,579	$0.2356		$118,408		0	0	502,579	$118,408	
18	TOTAL I30			$119,265	$121,270	$2,005				$121,270	$0
	Large Volume Industrial Service (I-32)										
19	Customer Charge	68	$100.00		$6,800		0		68	$6,800	
20	Distribution Margin Therms	1,246,247	$0.0952		$118,643		0	0	1,246,247	$118,643	
21	TOTAL I32			$121,731	$125,443	$3,712				$125,443	$0
	Large Volume Industrial Transportation Service (I-32)										
22	Customer Charge	141	$100.00		$14,100		0		141	$14,100	
23	Distribution Margin Therms	11,443,573	$0.0952		$1,089,428		0	0	11,443,573	$1,089,428	
24	TOTAL I32			$1,070,974	$1,103,528	$32,554				$1,103,528	$0
	Small Volume Public Authority (PA-40)										
25	Customer Charge	12,747	$13.50		$172,085		0		12,747	$172,085	
26	Customer Charge - CNG	82	$30.00		$2,460		0		82	$2,460	
27	Distribution Margin Therms	5,797,679	$0.2593		$1,503,338		0	(187,359)	5,610,320	$1,454,756	
28	TOTAL PA40			$1,652,382	$1,677,883	$25,500				$1,629,301	$48,582
	Large Volume Public Authority (PA-42)										
29	Customer Charge	60	$100.00		$6,000		0		60	$6,000	
30	Distribution Margin Therms	1,225,072	$0.1198		$146,764		0	(32,942)	1,192,130	$142,817	
31	TOTAL PA42			$149,735	$152,764	$3,029				$148,817	$3,947
	Large Volume Public Authority Transportation Service (PA-42)										
32	Customer Charge	86	$100.00		$8,600		0		86	$8,600	
33	Distribution Margin Therms	5,127,210	$0.1198		$614,240		0	0	5,127,210	$614,240	

UNS GAS, INC. PROOF OF ADJUSTED REVENUES
TEST PERIOD TME *JUNE 30, 2008*

Line No.	Class of Service	Total TY Unadjusted Billing Units	Existing Rates as of Dec 1, 2007	Unadjusted Revenues	Revenue Annualization	Revenue Annualization Adjustment	UNSG Adj. for Customer Annualizaton	UNSG Adj. for Weather Normalization	Adjusted Billing units	TY Adjusted Revenues	Total Customer & Weather Revenue Adjustment
34	TOTAL PA42			$611,520	$622,840	$11,320				$622,840	$0
	Special Gas Light Service (PA-44)										
35	Customer Charge Lighting Group A	108	$15.17		$1,638		0		108	$1,638	
36	Customer Charge Lighting Group B	3,588	$18.20		$65,302		0	0	3,588	$65,302	
37	TOTAL PA44	145,406		$64,425	$66,940	$2,515			145,406	$66,940	$0
	Irrigation Service (IR-60)										
38	Customer Charge	60	$13.50		$810				60	$810	
39	Distribution Margin Therms	104,267	$0.3192		$33,282		0	(712)	103,554	$33,055	
40	TOTAL IR60			$31,451	$34,092	$2,841			0	$33,865	$227
	T1 Contract Customers										
41	Customer Charge	36	$100.00		$3,600		0		36	$3,600	
42	Distribution Margin Therms	7,564,291	$0.0867		$655,582		0	0	7,564,291	$655,582	
43	TOTAL IR60			$658,957	$659,182	$225	-			$659,182	$0
	T2 - Customer										
44	Customer Charge	12	$100.00		$1,200		0		12	$1,200	
45	Distribution Margin Therms	1,151,133	$0.0544		$62,652		0	0	1,151,133	$62,652	
46	TOTAL IR60			$63,777	$63,852	$75				$63,852	$0
47	Customers	1,739,041					-		1,739,041		
48	Therms	133,433,766					-	(2,896,863)	140,518,475		
49	Revenue			$51,107,743	$52,556,220	$1,448,476 #				$51,673,767	$882,453

UNS GAS, INC. PROPOSED RATES AND PROPOSED REVENUES
TEST PERIOD TME JUNE 30, 2008

Line No.	Class of Service	Existing Rates as of Dec 1, 2007	Adjusted Billing units	TY Adjusted Revenues	Proposed Increase	Total Revenue Requirement	New Rates	Total Revenue Requirement	Percentage Increase
								Year 1	
	Residential Service (R10)								
1	Customer Charge	$8.50	1,507,223	$12,811,396			$10.00	$15,072,230	17.65%
2	Distribution Margin Therms	$0.3270	68,729,996	$22,474,709			$0.3027	$20,803,904	
3	**TOTAL R10**			$35,286,104	$590,030	$35,876,134		$35,876,134	1.67%
								$0	
	Residential Service Cares (R12)								
4	Customer Charge	$7.00	80,938	$566,566			$7.00	$566,566	0.00%
5	Distribution Margin Therms - Summer	$0.3270	614,997	$201,104			$0.3270	$201,104	
6	Distribution Margin Therms - Winter	$0.3270	386,887	$126,512			$0.3270	$126,512	
7	Distribution Margin Therms - Winter	$0.1770	2,376,593	$420,657			$0.1770	$420,657	
	TOTAL R12			$1,314,839	$0	$1,314,839		$1,314,839	0.00%
	Small Volume Commercial Service (C20)								
8	Customer Charge	$13.50	137,081	$1,850,594			$15.50	$2,124,756	14.81%
9	Distribution Margin Therms	$0.2638	29,562,033	$7,798,464			$0.2600	$7,685,647	
10	**TOTAL R20**			$9,649,058	$161,345	$9,810,403		$9,810,403	1.67%
								$0	
	Large Volume Commercial Service (C22)								
11	Customer Charge	$100.00	182	$18,200			$105.00	$19,110	5.00%
12	Distribution Margin Therms	$0.1718	1,416,892	$243,422			$0.1742	$246,887	
13	**TOTAL R22**			$261,622	$4,375	$265,997		$265,997	1.67%
	Large Volume Commercial Transportation Service (C22)								
14	Customer Charge	$100.00	125	$12,500			$105.00	$13,125	5.00%
15	Distribution Margin Therms	$0.1718	3,344,634	$574,608			$0.1742	$582,787	
16	**TOTAL R22**			$587,108	$9,817	$596,925		$595,912	1.50%
								-$1,014	
	Small Volume Industrial Service (I-30)								
16	Customer Charge	$13.50	212	$2,862			$15.50	$3,286	14.81%
17	Distribution Margin Therms	$0.2356	502,579	$118,408			$0.2388	$120,011	
18	**TOTAL I30**			$121,270	$2,028	$123,297		$123,297	1.67%
								$0	
	Large Volume Industrial Service (I-32)								
19	Customer Charge	$100.00	68	$6,800			$105.00	$7,140	5.00%
20	Distribution Margin Therms	$0.0952	1,246,247	$118,643			$0.0966	$120,400	
21	**TOTAL I32**			$125,443	$2,098	$127,540		$127,540	1.67%
	Large Volume Industrial Transportation Service (I-32)								
22	Customer Charge	$100.00	141	$14,100			$105.00	$14,805	5.00%
23	Distribution Margin Therms	$0.0952	11,443,573	$1,089,428			$0.0968	$1,107,176	
24	**TOTAL I32**			$1,103,528	$18,452	$1,121,981		$1,121,981	1.67%
								$0	
	Small Volume Public Authority (PA-40)								
25	Customer Charge	$13.50	12,747	$172,085			$15.50	$197,579	14.81%
26	Customer Charge - CNG	$30.00	82	$2,460			$15.50	$1,271	-48.33%
27	Distribution Margin Therms	$0.2593	5,610,320	$1,454,756			$0.2598	$1,457,695	0.20%
28	**TOTAL PA40**			$1,629,301	$27,244	$1,656,545		$1,656,545	
								$0	
	Large Volume Public Authority (PA-42)								
29	Customer Charge	$100.00	60	$6,000			$105.00	$6,300	
30	Distribution Margin Therms	$0.1198	1,192,130	$142,817			$0.1216	$145,006	

UNS GAS, INC. PROPOSED RATES AND PROPOSED REVENUES
TEST PERIOD TME JUNE 30, 2008

Line No.	Class of Service	Existing Rates as of Dec 1, 2007	Adjusted Billing units	TY Adjusted Revenues	Proposed Increase	Total Revenue Requirement	New Rates	Total Revenue Requirement	Percentage Increase
31	TOTAL PA42			$148,817	$2,488	$151,306		$151,306	1.67%
								$0	
	Large Volume Public Authority Transportation Service (PA-42)								
32	Customer Charge	$100.00	86	$8,600			$105.00	$9,030	5.00%
33	Distribution Margin Therms	$0.1198	5,127,210	$614,240			$0.1217	$624,224	
34	TOTAL PA42			$622,840	$10,415	$633,254		$633,254	1.67%
								$0	
	Special Gas Light Service (PA-44)								
35	Customer Charge Lighting Group A	$15.17	108	$1,638			$18.41	$1,989	21.39%
36	Customer Charge Lighting Group B	$18.20	3,588	$65,302			$18.41	$66,071	1.18%
37	TOTAL PA44		145,406	$66,940	$1,119	$68,059		$68,059	1.67%
								$0	
	Irrigation Service (IR-60)								
38	Customer Charge	$13.50	60	$810			$15.50	$930	14.81%
39	Distribution Margin Therms	$0.3192	103,554	$33,055			$0.3235	$33,501	
40	TOTAL IR60		0	$33,865	$566	$34,431		$34,431	1.67%
								$0	
	T1 Contract Customers								
41	Customer Charge	$100.00	36	$3,600			$105.00	$3,780	5.00%
42	Distribution Margin Therms	$0.0867	7,564,291	$655,582			$0.0881	$666,424	
43	TOTAL IR60			$659,182	$11,022	$670,204		$670,204	1.67%
								$0	
	T2 - Contract Customer								
44	Customer Charge	$100.00	12	$1,200			$105.00	$1,260	5.00%
45	Distribution Margin Therms	$0.0544	1,151,133	$62,652			$0.0553	$63,659	
46	TOTAL IR60			$63,852	$1,068	$64,919		$64,919	1.67%
								$0	
						0			
47	Customers		1,739,041						
48	Therms		140,518,475						
49	Revenue			$51,673,767	$841,000	$52,515,835		$52,514,821	1.63%

Exhibit 3
Schedule H – Bill Impacts

UNS Gas, Inc.
Summary of Revenues by Customer Classifications
Adjusted Present Rates And Proposed Rates
Test Year Ended June 30, 2008
(Thousands of Dollars)

Line No.	Class of Service	Adjusted Present Net Revenue	Proposed Net Revenue	Proposed Net Increase	Proposed Percent Increase (a)	Line No.
1	Residential Service	$36,600,943	$37,190,974	$590,030	1.61%	1
2	Commercial Gas Service	9,910,680	10,076,399	165,720	1.67%	2
3	Industrial Gas Service	246,712	250,838	4,125	1.67%	3
4	Public Authority Gas Service	1,778,118	1,807,850	29,732	1.67%	4
5	Special Gas Light Service	66,940	68,059	1,119	1.67%	5
6	Irrigation Service	33,865	34,431	566	1.67%	6
7	Transportation Customers	3,036,509	3,086,270	49,761	1.64%	7
8	Subtotal	51,673,767	52,514,821	841,054	1.63%	8
9	Other Operating Revenue	1,744,743	1,744,743	0	0.00%	9
10	Total	$53,418,510	$54,259,564	$841,054	1.57%	10

Supporting Schedules
(a) H-2 (P2)

Recap Schedules
A-1

UNS Gas, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Year Ended June 30, 2008

		Rate Schedule		Actual				Adjusted			
Line No.	Class of Service	Present	Proposed	Therm Sales	Average Number of Customers	Average Therm per Customer	Test Year End Adjustments	Therm Sales	Average Number of Customers	Average Therm per Customer	Line No.
1	Residential Service	R-10	R-10	70,723,037	125,602	563	(2,656,075)	68,066,962	125,602	542	1
2	Residential Service Cares	R-12	R-12	3,478,376	6,745	516	55,060	3,533,436	6,745	524	2
3	Small Volume Commercial Service	C-20	C-20	30,119,256	11,423	2,637	(827,599)	29,291,657	11,423	2,564	3
4	Large Volume Commercial Service	C-22	C-22	1,442,578	15	95,115	(104,334)	1,338,244	15	88,236	4
5	Commercial Transportation	C-22T1	C-22T1	3,344,634	10	321,085	(303,749)	3,040,885	10	291,925	5
6	Small Volume Industrial Service	I-30	I-30	502,579	18	28,448	51,187	553,766	18	31,345	6
7	Large Volume Industrial Service	I-32	I-32	1,246,247	6	219,926	(33,594)	1,212,653	6	213,998	7
8	Industrial Transportation	I-32 T1	I-32 T1	11,443,573	12	973,921	138,953	11,582,526	12	985,747	8
9	Industrial Transportation - Contracts	I-32 T1C	I-32 T1C	7,564,291	3	2,521,430	(2,396,706)	5,167,584	3	1,722,528	9
10	T2 Transportation	I-32 T2	I-32 T2	1,151,133	1	1,151,133	0	1,151,133	1	1,151,133	10
11	Small Volume Public Authority	P-40	P-40	5,797,679	1,069	5,423	(185,370)	5,612,308	1,069	5,250	11
12	Large Volume Public Authority	P-42	P-42	1,225,072	5	245,014	(32,942)	1,192,130	5	238,426	12
13	Public Authority Transportation	P-42T1	P-42T1	5,127,210	7	715,425	270,621	5,397,831	7	753,186	13
14	Special Gas Light Service	P-44	P-44	145,406	2	72,703	0	145,406	2	72,703	14
15	Irrigation Service	I-60	I-60	104,267	5	20,853	(712)	103,554	5	20,711	15
16	Total Gas Service			143,415,337	144,923	990	(6,025,261)	137,390,076	144,923	948	16

Note: Some transportation customers have more than one meter which is accounted for in this schedule.

UNS Gas, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Year Ended June 30, 2008

Line No.	Class of Service	Actual Net Revenue	Test Year End Adjustments	Adjusted Net Revenue	Proposed Increase $	Proposed Increase %	Proposed Net Revenue	Line No.
1	Residential Service	$35,937,829	($651,725)	$35,286,104	$590,030	1.67%	$35,876,134	1
2	Residential Service Cares	1,341,403	($26,564)	1,314,839	0	0.00%	$1,314,839	2
3	Small Volume Commercial Service	9,796,053	($146,996)	9,649,058	161,345	1.67%	$9,810,403	3
4	Large Volume Commercial Service	266,035	($4,413)	261,622	4,375	1.67%	$265,997	4
5	Commercial Transportation	587,108	$0	587,108	8,803	1.50%	$595,912	5
6	Small Volume Industrial Service	121,270	$0	121,270	2,028	1.67%	$123,297	6
7	Large Volume Industrial Service	125,443	$0	125,443	2,098	1.67%	$127,540	7
8	Industrial Transportation	1,103,528	$0	1,103,528	18,452	1.67%	$1,121,981	8
9	Industrial Transportation - Contracts	659,182	$0	659,182	11,022	1.67%	$670,204	9
10	T2 Transportation	63,852	$0	63,852	1,068	1.67%	$64,919	10
11	Small Volume Public Authority	1,677,883	($48,582)	1,629,301	27,244	1.67%	$1,656,545	11
12	Large Volume Public Authority	152,764	($3,947)	148,817	2,488	1.67%	$151,306	12
13	Public Authority Transportation	622,840	$0	622,840	10,415	1.67%	$633,254	13
14	Special Gas Light Service	66,940	$0	66,940	1,119	1.67%	$68,059	14
15	Irrigation Service	34,092	($227)	33,865	566	1.67%	$34,431	15
16	Total Gas Service	$52,556,220	($882,453)	$51,673,767	$841,054	1.63%	$52,514,821	16

UNS Gas, Inc.
Comparison of Present And Proposed Rates
Test Year Ended June 30, 2008

	Present Rate	Proposed Rate	Increase $	Increase %
Residential Service				
Customer Charge	$8.50	$10.00	$1.50	17.65%
Distribution Margin Therms	$0.3270	$0.3027	-$0.0243	-7.43%
Residential Service Cares (R12)				
Customer Charge	$7.00	$7.00	$0.00	0.00%
Distribution Margin Therms Summer	$0.3270	$0.3270	$0.00	0.00%
Distribution Margin Therms Winter (First 100 Therms)	$0.1770	$0.3270	$0.15	84.75%
Distribution Margin Therms Winter all additional therms	$0.3270	$0.1770	-$0.15	-45.87%
Small Commercial Service (C20)				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.2638	$0.2600	-$0.0038	-1.45%
Large Commercial Service (C22)				
Customer Charge	$100.00	$105.00	$5.00	5.00%
Distribution Margin Therms	$0.1718	$0.1742	$0.0024	1.42%
Small Volume Industrial Service (I-30):				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.2356	$0.2388	$0.0032	1.35%
Large Volume Industrial Service (I-32):				
Customer Charge	$100.00	$105.00	$5.00	5.00%
Distribution Margin Therms	$0.0952	$0.0966	$0.0014	1.48%
Small Volume PA (PA-40)				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.2593	$0.2598	$0.0005	0.20%
Large Volume PA (PA-42)				
Customer Charge	$100.00	$105.00	$5.00	5.00%
Distribution Margin Therms	$0.1198	$0.1216	$0.0018	1.53%
Special Gas Light Service (PA-44):				
Single Orifice	$23.72	$18.41	-$5.31	-22.37%
Double Orifice	$39.53	$36.83	-$2.70	-6.83%
Triple Orifice	$54.86	$55.24	$0.38	0.70%
Quadruple Orifice	$71.16	$73.66	$2.50	3.51%
Irrigation Service (IR-60)				
Customer Charge	$13.50	$15.50	$2.00	14.81%
Distribution Margin Therms	$0.3192	$0.3235	$0.0043	1.35%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Residential Service (R10)				
Customer Charge (Sum: Apr - Nov)	$8.50	$10.00		
Distribution Margin Therms	0.3270	0.3027		

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$10.14	$11.51	$1.38	13.6%
10	$11.77	$13.03	$1.26	10.7%
20	$15.04	$16.05	$1.01	6.7%
35	$19.95	$20.59	$0.65	3.3%
50	$24.85	$25.13	$0.28	1.1%
75	$33.03	$32.70	($0.32)	-1.0%
100	$41.20	$40.27	($0.93)	-2.3%
250	$90.25	$85.67	($4.58)	-5.1%
500	$172.00	$161.35	($10.65)	-6.2%

Residential Service (R10)				
Customer Charge (Win: Dec-Mar)	$8.50	$10.00		
Distribution Margin Therms	0.3270	$0.3027		

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$10.14	$11.51	$1.38	13.6%
10	$11.77	$13.03	$1.26	10.7%
20	$15.04	$16.05	$1.01	6.7%
35	$19.95	$20.59	$0.65	3.3%
50	$24.85	$25.13	$0.28	1.1%
75	$33.03	$32.70	($0.32)	-1.0%
100	$41.20	$40.27	($0.93)	-2.3%
250	$90.25	$85.67	($4.58)	-5.1%
500	$172.00	$161.35	($10.65)	-6.2%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Residential Service Cares (R12)		
Customer Charge (Summer)	$7.00	$7.00
Distribution Margin Therms	0.3270	0.3270

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$8.64	$8.64	$0.00	0.0%
10	$10.27	$10.27	$0.00	0.0%
20	$13.54	$13.54	$0.00	0.0%
35	$18.45	$18.45	$0.00	0.0%
50	$23.35	$23.35	$0.00	0.0%
75	$31.53	$31.53	$0.00	0.0%
100	$39.70	$39.70	$0.00	0.0%
250	$88.75	$88.75	$0.00	0.0%
500	$170.50	$170.50	$0.00	0.0%

Residential Service Cares (R12)		
Customer Charge (Winter)	$7.00	$7.00
Distribution Margin Therms (1st 100 Therms)	0.1770	0.1770
Distribution Margin all additional Therms	0.3270	0.3270

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5	$7.89	$7.89	$0.00	0.0%
10	$8.77	$8.77	$0.00	0.0%
20	$10.54	$10.54	$0.00	0.0%
35	$13.20	$13.20	$0.00	0.0%
50	$15.85	$15.85	$0.00	0.0%
75	$20.28	$20.28	$0.00	0.0%
100	$24.70	$24.70	$0.00	0.0%
250	$73.75	$73.75	$0.00	0.0%
500	$155.50	$155.50	$0.00	0.0%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Small Commercial Service (C20)		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2638	$0.2600

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$26.69	$28.50	$1.81	6.8%
100	$39.88	$41.50	$1.62	4.1%
500	$145.40	$145.49	$0.09	0.1%
1,000	$277.30	$275.48	($1.82)	-0.7%
1,500	$409.20	$405.48	($3.72)	-0.9%
2,500	$673.00	$665.46	($7.54)	-1.1%
5,000	$1,332.50	$1,315.42	($17.08)	-1.3%
7,500	$1,992.00	$1,965.38	($26.62)	-1.3%
10,000	$2,651.50	$2,615.34	($36.16)	-1.4%

Large Commercial Service (C22)		
Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.1718	$0.1742

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,001	$1,818	$1,848	$29	1.6%
12,500	$2,248	$2,283	$36	1.6%
15,000	$2,677	$2,719	$42	1.6%
17,500	$3,107	$3,154	$48	1.5%
20,000	$3,536	$3,590	$54	1.5%
25,000	$4,395	$4,461	$66	1.5%
30,000	$5,254	$5,332	$78	1.5%
45,000	$7,831	$7,946	$115	1.5%
75,000	$12,985	$13,173	$188	1.5%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Small Volume Industrial Service (I-30):		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2356	$0.2388

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$25.28	$27.44	$2.16	8.5%
100	$37.06	$39.38	$2.32	6.3%
500	$131.30	$134.90	$3.60	2.7%
1,000	$249.10	$254.29	$5.19	2.1%
1,500	$366.90	$373.69	$6.79	1.8%
2,500	$602.50	$612.48	$9.98	1.7%
5,000	$1,191.50	$1,209.46	$17.96	1.5%
7,500	$1,780.50	$1,806.43	$25.93	1.5%
10,000	$2,369.50	$2,403.41	$33.91	1.4%

Large Volume Industrial Service (I-32):		
Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.0952	$0.0966

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,001	$1,052.10	$1,071.20	$19.10	1.8%
15,000	$1,528.00	$1,554.15	$26.15	1.7%
20,000	$2,004.00	$2,037.21	$33.21	1.7%
30,000	$2,956.00	$3,003.31	$47.31	1.6%
50,000	$4,860.00	$4,935.51	$75.51	1.6%
75,000	$7,240.00	$7,350.77	$110.77	1.5%
100,000	$9,620.00	$9,766.03	$146.03	1.5%
125,000	$12,000.00	$12,181.29	$181.29	1.5%
150,000	$14,380.00	$14,596.54	$216.54	1.5%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Small Volume Public Authority (PA-40)		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2593	$0.2598

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$26.47	$28.49	$2.03	7.7%
100	$39.43	$41.48	$2.05	5.2%
500	$143.15	$145.41	$2.26	1.6%
1,000	$272.80	$275.32	$2.52	0.9%
1,500	$402.45	$405.24	$2.79	0.7%
2,500	$661.75	$665.06	$3.31	0.5%
5,000	$1,310.00	$1,314.62	$4.62	0.4%
7,500	$1,958.25	$1,964.18	$5.93	0.3%
10,000	$2,606.50	$2,613.74	$7.24	0.3%

Large Volume Public Authority (PA-42)		
Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.1198	$0.1216

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,001	$1,298.12	$1,321.48	$23.36	1.8%
15,000	$1,897.00	$1,929.54	$32.54	1.7%
20,000	$2,496.00	$2,537.71	$41.71	1.7%
30,000	$3,694.00	$3,754.07	$60.07	1.6%
50,000	$6,090.00	$6,186.79	$96.79	1.6%
75,000	$9,085.00	$9,227.68	$142.68	1.6%
100,000	$12,080.00	$12,268.57	$188.57	1.6%
125,000	$15,075.00	$15,309.47	$234.47	1.6%
150,000	$18,070.00	$18,350.36	$280.36	1.6%

UNS Gas, Inc.
Typical Bill Comparison - Present And Proposed Rates
Test Year Ended June 30, 2008

Special Gas Light Service (PA-44):		
Customer Charge Lighting Group A	$15.17	$18.41
Customer Charge Lighting Group B	$18.20	$18.41

Average Montly Customers	Annual Bill Present	Annual Bill Proposed	Proposed Increase $	Proposed Increase %
The following is an annual delivery bill per lamp				
Customer Charge Lighting Group A	$182.04	$220.97	$38.93	21.4%
Customer Charge Lighting Group B	$218.40	$220.97	$2.57	1.2%

Note: There is no longer a Group A and Group B rate. All current customers are applicable to the Single Orifice Rate.

Irrigation Service (IR-60)		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.3192	$0.3235

Average Therms per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
50	$29.46	$31.68	$2.22	7.5%
100	$45.42	$47.85	$2.43	5.4%
500	$173.10	$177.25	$4.15	2.4%
1,000	$332.70	$339.01	$6.31	1.9%
1,500	$492.30	$500.76	$8.46	1.7%
2,500	$811.50	$824.27	$12.77	1.6%
5,000	$1,609.50	$1,633.05	$23.55	1.5%
7,500	$2,407.50	$2,441.82	$34.32	1.4%
10,000	$3,205.50	$3,250.59	$45.09	1.4%

UNS Gas Inc.
Residential Bill Count
Test Year Ended June 30, 2008

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
RESIDENTIAL SERVICE RATE R-10							
0	4	147,084	262,849	147,084	9.8%	262,849	0.4%
5	9	171,684	1,192,055	318,768	21.3%	1,454,904	2.1%
10	14	166,473	1,951,866	485,241	32.4%	3,406,770	5.0%
15	19	142,975	2,376,119	628,216	41.9%	5,782,889	8.5%
20	24	104,527	2,253,814	732,742	48.9%	8,036,703	11.8%
25	29	84,218	2,234,609	816,961	54.5%	10,271,312	15.1%
30	34	66,359	2,088,008	883,320	58.9%	12,359,320	18.2%
35	39	56,108	2,043,097	939,427	62.6%	14,402,416	21.2%
40	44	48,058	1,984,852	987,485	65.9%	16,387,268	24.1%
45	49	42,192	1,950,246	1,029,677	68.7%	18,337,514	26.9%
50	54	39,086	2,000,309	1,068,764	71.3%	20,337,823	29.9%
55	59	34,616	1,941,915	1,103,379	73.6%	22,279,738	32.7%
60	64	32,491	1,983,631	1,135,871	75.7%	24,263,369	35.6%
65	69	29,440	1,942,862	1,165,311	77.7%	26,206,230	38.5%
70	74	26,766	1,898,738	1,192,077	79.5%	28,104,968	41.3%
75	79	25,101	1,903,764	1,217,178	81.2%	30,008,732	44.1%
80	84	23,195	1,872,920	1,240,373	82.7%	31,881,652	46.8%
85	89	22,160	1,898,794	1,262,533	84.2%	33,780,446	49.6%
90	94	19,996	1,812,496	1,282,529	85.5%	35,592,943	52.3%
95	99	18,769	1,793,949	1,301,298	86.8%	37,386,892	54.9%
100	104	17,015	1,709,036	1,318,313	87.9%	39,095,928	57.4%
105	109	15,634	1,647,042	1,333,947	89.0%	40,742,969	59.9%
110	114	14,801	1,632,328	1,348,748	89.9%	42,375,297	62.3%
115	119	13,521	1,558,532	1,362,269	90.8%	43,933,829	64.5%
120	124	11,779	1,415,846	1,374,049	91.6%	45,349,675	66.6%
125	129	11,170	1,397,071	1,385,219	92.4%	46,746,747	68.7%
130	134	9,920	1,289,603	1,395,140	93.0%	48,036,349	70.6%
135	139	9,413	1,270,375	1,404,552	93.7%	49,306,724	72.4%
140	144	8,428	1,179,089	1,412,980	94.2%	50,485,813	74.2%
145	149	7,611	1,101,882	1,420,591	94.7%	51,587,695	75.8%
150	154	6,978	1,044,501	1,427,569	95.2%	52,632,196	77.3%
155	159	6,445	996,611	1,434,014	95.6%	53,628,806	78.8%
160	164	5,794	924,943	1,439,808	96.0%	54,553,749	80.1%
165	169	5,115	841,987	1,444,923	96.4%	55,395,736	81.4%
170	174	4,724	800,358	1,449,647	96.7%	56,196,095	82.6%
175	179	4,310	751,397	1,453,957	97.0%	56,947,492	83.7%
180	184	3,945	707,364	1,457,903	97.2%	57,654,856	84.7%
185	189	3,488	642,571	1,461,391	97.5%	58,297,427	85.6%
190	194	3,211	607,402	1,464,602	97.7%	58,904,829	86.5%
195	199	2,802	543,938	1,467,404	97.9%	59,448,767	87.3%
200	299	25,263	5,859,005	1,492,668	99.5%	65,307,772	95.9%
300	399	4,674	1,553,213	1,497,342	99.9%	66,860,985	98.2%
400	499	1,194	518,440	1,498,536	99.9%	67,379,425	99.0%
500	999	884	545,180	1,499,419	100.0%	67,924,605	99.8%
1,000	1,999	76	97,646	1,499,495	100.0%	68,022,251	99.9%
≥ 2,000		17	44,711	1,499,512	100.0%	68,066,962	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
RESIDENTIAL SERVICE RATE R-12							
0	4	5,459	12,331	5,459	6.4%	12,331	0.3%
5	9	10,624	76,405	16,082	18.9%	88,737	2.5%
10	14	10,301	125,639	26,384	31.1%	214,375	6.1%
15	19	9,085	156,305	35,469	41.8%	370,680	10.5%
20	24	6,551	146,395	42,019	49.5%	517,076	14.6%
25	29	5,236	144,026	47,255	55.6%	661,102	18.7%
30	34	4,038	131,678	51,293	60.4%	792,780	22.4%
35	39	3,373	127,317	54,667	64.4%	920,096	26.0%
40	44	3,032	129,564	57,699	67.9%	1,049,660	29.7%
45	49	2,653	127,105	60,352	71.1%	1,176,765	33.3%
50	54	2,453	130,177	62,805	74.0%	1,306,942	37.0%
55	59	2,074	120,537	64,879	76.4%	1,427,479	40.4%
60	64	2,031	128,330	66,910	78.8%	1,555,808	44.0%
65	69	1,801	123,134	68,711	80.9%	1,678,943	47.5%
70	74	1,663	122,206	70,374	82.9%	1,801,149	51.0%
75	79	1,530	120,151	71,904	84.7%	1,921,300	54.4%
80	84	1,361	113,847	73,265	86.3%	2,035,147	57.6%
85	89	1,300	115,400	74,565	87.8%	2,150,548	60.9%
90	94	1,140	107,205	75,706	89.1%	2,257,753	63.9%
95	99	1,045	103,439	76,750	90.4%	2,361,192	66.8%
100	104	903	94,006	77,653	91.4%	2,455,198	69.5%
105	109	823	89,783	78,476	92.4%	2,544,982	72.0%
110	114	787	89,920	79,263	93.3%	2,634,901	74.6%
115	119	661	78,915	79,923	94.1%	2,713,816	76.8%
120	124	557	69,294	80,480	94.8%	2,783,111	78.8%
125	129	504	65,386	80,985	95.4%	2,848,497	80.6%
130	134	458	61,736	81,443	95.9%	2,910,232	82.4%
135	139	445	62,184	81,887	96.4%	2,972,417	84.1%
140	144	362	52,346	82,249	96.9%	3,024,762	85.6%
145	149	349	52,376	82,598	97.3%	3,077,138	87.1%
150	154	258	39,939	82,856	97.6%	3,117,077	88.2%
155	159	230	36,871	83,086	97.8%	3,153,949	89.3%
160	164	209	34,441	83,295	98.1%	3,188,389	90.2%
165	169	167	28,511	83,462	98.3%	3,216,901	91.0%
170	174	194	34,100	83,656	98.5%	3,251,000	92.0%
175	179	137	24,682	83,793	98.7%	3,275,682	92.7%
180	184	128	23,850	83,921	98.8%	3,299,532	93.4%
185	189	126	24,112	84,048	99.0%	3,323,644	94.1%
190	194	98	19,125	84,145	99.1%	3,342,769	94.6%
195	199	108	21,712	84,253	99.2%	3,364,481	95.2%
200	299	591	139,942	84,844	99.9%	3,504,422	99.2%
300	399	70	23,854	84,914	100.0%	3,528,276	99.9%
400	499	7	3,151	84,921	100.0%	3,531,428	99.9%
500	999	3	2,008	84,924	100.0%	3,533,436	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME COMMERCIAL RATE C-20							
0	9	45,637	93,478	45,637	33.4%	93,478	0.3%
10	19	11,797	162,319	57,434	42.0%	255,798	0.9%
20	29	7,608	180,216	65,042	47.6%	436,014	1.5%
30	39	5,567	187,261	70,609	51.7%	623,275	2.1%
40	49	4,652	202,215	75,261	55.1%	825,490	2.8%
50	59	3,958	210,633	79,219	58.0%	1,036,123	3.5%
60	69	3,356	211,655	82,575	60.4%	1,247,778	4.3%
70	79	2,886	210,179	85,461	62.6%	1,457,958	5.0%
80	89	2,573	212,899	88,034	64.4%	1,670,857	5.7%
90	99	2,264	209,493	90,298	66.1%	1,880,350	6.4%
100	109	2,137	218,373	92,436	67.7%	2,098,724	7.2%
110	119	1,947	217,863	94,382	69.1%	2,316,587	7.9%
120	129	1,757	214,256	96,139	70.4%	2,530,842	8.6%
130	139	1,558	205,156	97,698	71.5%	2,735,998	9.3%
140	149	1,480	209,601	99,178	72.6%	2,945,599	10.1%
150	159	1,434	216,925	100,612	73.6%	3,162,524	10.8%
160	169	1,310	211,315	101,922	74.6%	3,373,839	11.5%
170	179	1,173	200,443	103,095	75.5%	3,574,282	12.2%
180	189	1,124	202,795	104,219	76.3%	3,777,076	12.9%
190	199	1,085	206,800	105,304	77.1%	3,983,877	13.6%
200	249	4,395	960,820	109,699	80.3%	4,944,697	16.9%
250	299	3,384	906,615	113,083	82.8%	5,851,312	20.0%
300	349	2,746	871,124	115,829	84.8%	6,722,436	23.0%
350	399	2,247	823,754	118,076	86.4%	7,546,190	25.8%
400	449	1,958	813,951	120,033	87.9%	8,360,141	28.5%
450	499	1,713	796,260	121,747	89.1%	9,156,401	31.3%
500	599	2,650	1,419,229	124,397	91.1%	10,575,631	36.1%
600	699	2,002	1,267,932	126,399	92.5%	11,843,563	40.4%
700	799	1,545	1,129,873	127,944	93.6%	12,973,436	44.3%
800	899	1,212	1,005,484	129,155	94.5%	13,978,920	47.7%
900	999	916	849,267	130,071	95.2%	14,828,187	50.6%
1,000	1,499	2,912	3,475,058	132,984	97.3%	18,303,245	62.5%
1,500	1,999	1,443	2,438,885	134,426	98.4%	20,742,130	70.8%
2,000	2,999	1,145	2,706,208	135,572	99.2%	23,448,338	80.1%
3,000	3,999	416	1,391,628	135,988	99.5%	24,839,965	84.8%
4,000	4,999	183	793,480	136,170	99.7%	25,633,445	87.5%
5,000	5,999	132	712,597	136,303	99.8%	26,346,042	89.9%
6,000	6,999	84	533,014	136,387	99.8%	26,879,056	91.8%
7,000	7,999	62	455,483	136,449	99.9%	27,334,539	93.3%
8,000	8,999	37	303,016	136,486	99.9%	27,637,555	94.4%
9,000	9,999	39	358,260	136,524	99.9%	27,995,815	95.6%
10,000	10,999	32	323,236	136,556	100.0%	28,319,051	96.7%
11,000	11,999	22	244,189	136,578	100.0%	28,563,240	97.5%
12,000	12,999	13	156,847	136,590	100.0%	28,720,087	98.0%
13,000	13,999	1	13,058	136,591	100.0%	28,733,145	98.1%
14,000	14,999	9	127,467	136,600	100.0%	28,860,612	98.5%
≥ 15,000		20	431,045	136,620	100.0%	29,291,657	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
LARGE VOLUME COMMERCIAL RATE C-22							
0	249	51	2,411	51	30.4%	2,411	0.2%
250	499	15	5,249	66	39.1%	7,660	0.6%
500	749	15	9,297	80	47.8%	16,957	1.3%
750	999	1	914	81	48.4%	17,872	1.3%
1,000	1,999	2	2,561	83	49.5%	20,432	1.5%
2,000	2,999	2	5,483	85	50.5%	25,915	1.9%
3,000	3,999	5	19,333	90	53.8%	45,248	3.4%
4,000	4,999	3	13,056	93	55.4%	58,304	4.4%
5,000	5,999	7	41,464	100	59.8%	99,768	7.5%
6,000	6,999	6	42,774	107	63.6%	142,542	10.7%
7,000	7,999	3	21,534	110	65.2%	164,076	12.3%
8,000	8,999	4	32,672	113	67.4%	196,748	14.7%
9,000	9,999	3	26,598	116	69.0%	223,346	16.7%
10,000	19,999	34	564,529	150	89.1%	787,875	58.9%
20,000	29,999	12	295,317	162	96.2%	1,083,192	80.9%
30,000	39,999	5	161,749	166	98.9%	1,244,941	93.0%
40,000	49,999	1	46,128	167	99.5%	1,291,069	96.5%
50,000	59,999	1	47,176	168	100.0%	1,338,244	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME INDUSTRIAL RATE I-30							
0	249	82	3,300	82	34.3%	3,300	0.6%
250	499	13	4,204	95	39.5%	7,503	1.4%
500	749	17	9,111	112	46.7%	16,614	3.0%
750	999	11	8,272	123	51.4%	24,886	4.5%
1,000	1,499	13	13,631	136	56.7%	38,517	7.0%
1,500	1,999	8	12,616	144	60.0%	51,133	9.2%
2,000	2,499	3	6,545	147	61.4%	57,678	10.4%
2,500	2,999	8	19,539	155	64.8%	77,217	13.9%
3,000	3,499	13	35,039	168	70.0%	112,255	20.3%
3,500	3,999	9	28,921	177	73.8%	141,176	25.5%
4,000	4,499	5	16,855	182	75.7%	158,031	28.5%
4,500	4,999	7	28,308	189	78.6%	186,339	33.6%
5,000	5,499	10	47,089	199	82.9%	233,428	42.2%
5,500	5,999	8	40,151	207	86.2%	273,579	49.4%
6,000	6,499	1	6,130	208	86.7%	279,709	50.5%
6,500	6,999	8	46,506	216	90.0%	326,215	58.9%
7,000	7,499	6	35,617	222	92.4%	361,832	65.3%
7,500	7,999	3	22,790	225	93.8%	384,622	69.5%
8,500	8,999	2	16,928	227	94.8%	401,550	72.5%
9,000	9,499	1	8,968	229	95.2%	410,518	74.1%
9,500	9,999	1	9,325	230	95.7%	419,843	75.8%
10,000	10,999	1	9,939	231	96.2%	429,782	77.6%
11,000	11,999	2	23,175	233	97.1%	452,957	81.8%
12,000	12,999	2	24,844	235	98.1%	477,800	86.3%
14,000	14,999	2	28,452	238	99.0%	506,252	91.4%
19,000	19,999	1	19,143	239	99.5%	525,395	94.9%
28,000	28,999	1	28,371	240	100.0%	553,766	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
LARGE VOLUME INDUSTRIAL RATE I-32							
0	499	9	517	9	15.7%	517	0.0%
500	999	3	2,178	12	20.0%	2,695	0.2%
1,000	1,999	1	1,570	13	21.4%	4,265	0.4%
3,000	3,999	1	3,182	14	22.9%	7,447	0.6%
4,000	4,999	2	8,248	15	25.7%	15,695	1.3%
5,000	9,999	9	91,679	25	41.4%	107,374	8.9%
10,000	14,999	11	160,059	36	60.0%	267,433	22.1%
15,000	19,999	10	205,704	46	77.1%	473,137	39.0%
20,000	29,999	6	162,332	52	87.1%	635,469	52.4%
30,000	39,999	2	66,882	54	90.0%	702,351	57.9%
40,000	49,999	1	40,506	55	91.4%	742,857	61.3%
50,000	59,999	1	52,592	56	92.9%	795,449	65.6%
60,000	69,999	2	128,029	57	95.7%	923,478	76.2%
75,000	125,000	3	289,176	60	100.0%	1,212,653	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
SMALL VOLUME PUBLIC AUTHORITY RATE P-40							
0	49	5,942	72,013	5,942	46.5%	72,013	1.3%
50	99	1,332	93,099	1,332	10.4%	165,112	2.9%
100	199	1,367	190,289	1,367	10.7%	355,400	6.3%
200	299	745	177,867	745	5.8%	533,268	9.5%
300	399	545	181,987	545	4.3%	715,255	12.7%
400	499	418	181,359	418	3.3%	896,614	16.0%
500	599	293	155,157	293	2.3%	1,051,772	18.7%
600	699	220	137,566	220	1.7%	1,189,337	21.2%
700	799	203	146,683	203	1.6%	1,336,021	23.8%
800	899	161	131,699	161	1.3%	1,467,720	26.2%
900	999	133	122,012	133	1.0%	1,589,732	28.3%
1,000	1,999	698	956,175	698	5.5%	2,545,906	45.4%
2,000	2,999	301	711,158	301	2.4%	3,257,065	58.1%
3,000	3,999	134	443,779	134	1.0%	3,700,844	66.0%
4,000	4,999	105	453,501	105	0.8%	4,154,345	74.0%
5,000	6,999	97	545,552	97	0.8%	4,699,896	83.8%
7,000	9,999	47	381,443	47	0.4%	5,081,339	90.6%
10,000	19,999	34	438,273	34	0.3%	5,519,612	98.4%
20,000	29,999	4	91,041	4	0.0%	5,610,653	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
LARGE VOLUME PUBLIC AUTHORITY RATE P-42							
600	799	1	605	1	1.7%	605	0.1%
800	999	2	1,742	3	5.0%	2,346	0.2%
1,000	5,999	4	5,281	7	11.7%	7,627	0.6%
6,000	7,999	4	26,637	11	18.3%	34,264	2.9%
8,000	9,999	5	41,881	16	26.7%	76,146	6.4%
10,000	12,999	8	89,684	24	40.0%	165,830	13.9%
13,000	15,999	3	44,641	27	45.0%	210,471	17.7%
16,000	18,999	5	82,950	32	53.3%	293,421	24.6%
19,000	23,999	6	115,842	38	63.3%	409,264	34.3%
24,000	26,999	8	199,194	46	76.7%	608,458	51.0%
27,000	29,999	3	82,833	49	81.7%	691,290	58.0%
30,000	39,999	4	135,070	53	88.3%	826,361	69.3%
40,000	59,999	5	235,294	58	96.7%	1,061,655	89.1%
60,000	70,000	2	130,475	60	100.0%	1,192,130	100.0%

Usage Range - Therms				Cumulative Bills		Cumulative Therms	
Lower	Upper	Number of Bills	Therms	Bills	Percent of Total	Therms	Percent of Total
IRRIGATION SERVICE RATE I-60							
0	99	40	215	40	66.7%	215	0.2%
100	199	3	406	43	71.7%	620	0.6%
1,700	1,799	1	1,821	44	73.3%	2,441	2.4%
1,800	1,899	1	1,901	45	75.0%	4,343	4.2%
1,900	1,999	1	1,982	46	76.7%	6,325	6.1%
2,100	2,199	1	2,276	47	78.3%	8,600	8.3%
2,200	2,299	1	2,340	48	80.0%	10,941	10.6%
2,400	2,499	1	2,546	49	81.7%	13,486	13.0%
2,900	2,999	1	3,107	50	83.3%	16,593	16.0%
3,000	3,099	1	3,153	51	85.0%	19,746	19.1%
3,200	3,299	1	3,411	52	86.7%	23,157	22.4%
3,400	3,499	1	3,644	53	88.3%	26,802	25.9%
3,600	3,699	1	3,846	54	90.0%	30,647	29.6%
4,200	4,299	1	4,450	55	91.7%	35,098	33.9%
4,400	4,499	1	4,654	56	93.3%	39,751	38.4%
10,500	10,599	1	10,996	57	95.0%	50,747	49.0%
11,900	11,999	1	12,416	58	96.7%	63,163	61.0%
16,900	16,999	1	17,693	59	98.3%	80,856	78.1%
21,700	21,799	1	22,699	60	100.0%	103,554	100.0%

EXHIBIT
R-12
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
Kristen K. Mayes – Chairman
Gary Pierce
Sandra D. Kennedy
Paul Newman
Bob Stump

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	**DOCKET No. G-04204A-08-0571**

SURREBUTTAL TESTIMONY

OF

FRANK W. RADIGAN

ON BEHALF OF
RESIDENTIAL UTLITIY CONUSMER OFFICE OF ARIZONA

Phoenix, Arizona
July 29, 2009

SURREBUTAL TESTIMONY OF FRANK W. RADIGAN
EXECUTIVE SUMMARY

1) The Company's proposed rate design that would phase in a 65% increase in the residential customer charge over three years should be rejected. The Company has presented no new evidence in its rebuttal testimony. The main argument is that the $5.50 increase that it wishes to impose is relatively small in absolute terms and the rate shock is ameliorated by the phase-in over three years. In this testimony and my initial testimony I disagreed with a phase-in in order to avoid customer complaints and agreed to an 18% increase, $1.5 per month for Residential customers. I view this increase at the top of an acceptable bill impact range given that RUCO is recommending a 1.6% overall increase.

I. INTRODUCTION

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

A. Frank W. Radigan. I am a principal in the Hudson River Energy Company, a consulting firm providing services to the utility industry and specializing in the fields of rates, planning, and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Residential Utility Consumer Office of Arizona ("RUCO").

Q. Are you the same Frank W. Radigan that previously provided testimony in this proceeding?

A. Yes, I provided the RUCO position on cost of service, revenue allocation and rate design.

Q. What is the purpose of the testimony you are presenting?

A. I have been asked to discuss the reasonableness of UNS Gas, Inc.'s ("UNS" or the "Company") rebuttal testimony on rate design.

Q. Could you please summarize the Company's rebuttal testimony?

A. The Company's proposed rate design that would phase in a $5.50 (65%) increase in the residential customer charge over three years. Company witness Erdwurm argues that too much emphasis is being placed on the bill impacts resulting from his proposal (Erdwurm Rebuttal, page 12). Mr. Erdwurm argues that when presented in percentage terms, the increase in customer charges approximates 65% and appears high, but when viewed in absolute terms, the increase in the charge over three years, from $8.50 to $14.00 per month, totals $5.50 per month, the price of a typical fast food meal (Id).

Q. Could you please comment on the Company's arguments?

A. Yes, I did support the Company proposal to increase the customer charge from $8.50 per month to $10 per month in the rate year. I felt the $1.50 per month or 17.6% increase balanced the desire to increase the customer charge to reflect the cost to serve without imposing undue rate shock. The $5.50 per month increase, 65%, would be unacceptable in terms of rate shock based on the Company's proposed rate increase of 6% and is quite unacceptable given RUCO's proposed rate increase of 1.6%. One should remember that this rate case is not the only rate case that the utility will ever have given that the Company last had a rate increase just two years ago. Thus, the argument is not that we should not be moving the customer charge closer to the cost of service, but at what pace. My recommendation is a much more measured pace than what the Company proposes.

Phasing in the increase in the customer charge does not solve the bill impact issue. As I discussed in my original testimony, a phased increase is undesirable from a customer acceptance point of view (Radigan pre-filed testimony page 6). Based on my 27 years of experience in the utility industry (gas, electric, water and steam) in which I worked for utility regulatory Commissions, public utility advocate offices, a number of municipal utilities and individual customers, customer's do not like, and do complain, about rate increases and especially outside of a rate case. A good example of customer dissatisfaction with utility rate increases is a recent United Illuminating rate case in Connecticut. As noted by the Department of Public Utility Control in its order: "The Department received more than 1000 letters and email correspondence regarding the Company's application. They were unanimous in their opposition to the proposed rate increase. Many were concerned with the state of the economy and its effect on homeowners and businesses, and their ability to pay bills." (Docket No. 08-07-04, Application of the United Illuminating Company to Increase its Rates and Charges, Final Decision issued February 4, 2009). Even if one did want to consider further increases in the customer charge, it should not be done outside of a rate case.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT
R-13
ADMITTED

UNS GAS, INC.

DOCKET NO. G-04204A-08-0571

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 8, 2009

DIRECT TESTIMONY OF WILLIAM A. RIGSBY, CRRA

EXECUTIVE SUMMARY

Original Cost of Equity Capital – The Residential Utility Consumer Office ("RUCO") recommends an 8.61 percent original cost of equity capital for UNS Gas, Inc. ("UNSG" or "Company"). This 8.61 percent original cost figure is based on the results obtained in a cost of equity analysis, which employed both the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") methodologies. RUCO's recommended 8.61 percent figure is 239 basis points lower than the Company-proposed cost of equity capital of 11.00 percent.

Cost of Debt – Based on a review of the costs associated with UNSG's various debt instruments, RUCO recommends that the Company-proposed 6.49 percent cost of debt be adopted by the Arizona Corporation Commission ("ACC" or "Commission").

Capital Structure – RUCO recommends that the Company-proposed capital structure, which is comprised of 50.01 percent debt and 49.99 percent common equity, be adopted by the Commission.

Original Cost Rate of Return – Based on the results of RUCO's recommended capital structure, original cost of equity capital, and debt analyses, RUCO recommends a 7.55 percent original cost rate of return ("OCROR") for UNSG. This figure represents the weighted average cost of RUCO's recommended 8.61

percent original cost of equity capital and RUCO's 6.49 percent recommended cost of debt. RUCO's recommended 7.55 percent OCROR is 120 basis points lower than the Company-proposed unadjusted 8.75 percent weighted average cost of capital.

Fair Value Rate of Return – RUCO is recommending a 5.38 percent fair value rate of return ("FVROR") which is 217 basis points lower than RUCO's recommended 7.55 percent OCROR. In arriving at this 5.38 percent FVROR figure, RUCO considered a range of possible returns that could be applied to the Company's fair value rate base. The method that RUCO used to arrive at its recommended 5.38 percent FVROR comports with the provisions of Decision No. 70441, dated July 28, 2008, that resulted from a prior remand proceeding which involved Chaparral City Water Company. The methodology that RUCO relied on to arrive at its recommended FVROR figure is explained fully in the testimony of RUCO witness Ralph Smith.

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INTRODUCTION

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

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

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

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of UNS Gas, Inc.'s ("UNSG" or "Company") application for a permanent rate increase ("Application") for the Company's natural gas distribution operations in northern Arizona and Santa Cruz County in southern Arizona. UNSG filed the Application with the ACC on November 7, 2008. The Company has chosen the fiscal year ended June 30, 2008 for the test year in this proceeding.

Q. Briefly describe UNSG.

A. UNSG serves customers in a number of areas in northern Arizona including Flagstaff, Kingman and Prescott. The Company also provides service to customers in Santa Cruz County in the southern half of the state. UNSG is a wholly owned subsidiary of UniSource Energy Services, which is owned by UniSource Energy Corporation ("UniSource" or "Parent"), an Arizona corporation, based in Tucson, that is publicly traded on the New York Stock Exchange ("NYSE")[1]. UniSource is also the parent company of Tucson Electric Power, the second largest investor owned electric utility in the state. In addition to natural gas distribution, UniSource also provides electric service through its other subsidiary UNS Electric, Inc., to customers in Mohave and Santa Cruz Counties.

[1] NYSE ticker symbol UNS.

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

A. I reviewed UNSG's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity and my recommended cost of long-term debt (the Company has no short-term debt or preferred stock). The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Is this your first case involving UNSG?

A. No. In 2003 I was involved with UniSource's acquisition of UniSource Energy Corporation's gas and electric assets from Citizens' Utilities Company. The UNSG entity was the result of that acquisition. I also provided cost of capital testimony in the Company's most recent rate case proceeding which resulted in Decision No. 70011, dated November 27, 2007. UNSG's present rates were established in that Decision.

...

Q. Were you also responsible for conducting an analysis of the Company's proposed revenue level, rate base and rate design?

A. No. Those aspects of the case were handled by two outside consultants. Mr. Ralph Smith, of Larkin & Associates, will provide testimony on RUCO's recommended level of required revenue (based on his adjustments to Company-proposed levels of rate base and operating expense). Mr. Smith will also provide testimony on the methodology that RUCO employed to arrive at its recommended rate of return on UNSG's fair value rate base. Mr. Frank Radigan, of Hudson River Energy Group, will provide testimony on RUCO's recommended rate design.

Q. What areas will you address in your testimony?

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

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into seven sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow

("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this second section I will also provide a brief overview of the economic climate that UNSG is currently operating in. Fourth, I will discuss my recommended cost of debt. Fifth, I will compare my recommended capital structure with the Company-proposed capital structure. Sixth, I will explain my weighted cost of capital recommendation and seventh, I will comment on UNSG's cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

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

A. Based on the results of my analysis of UNSG, I am making the following recommendations:

Original Cost of Equity Capital – I am recommending an 8.61 percent original cost of equity capital. This 8.61 percent original cost figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies. My recommended

8.61 percent figure is 239 basis points lower than the Company-proposed cost of equity capital of 11.00 percent.

Cost of Debt – Based on my review of the costs associated with UNSG's various debt instruments, I am recommending that the Company-proposed 6.49 percent cost of debt be adopted by the Commission.

Capital Structure – I am recommending that the Company-proposed capital structure, which is comprised of 50.01 percent debt and 49.99 percent common equity, be adopted by the Commission.

Original Cost Rate of Return – Based on the results of my recommended capital structure, original cost of equity capital, and debt analyses, I am recommending a 7.55 percent original cost rate of return ("OCROR") for UNSG. This figure represents the weighted average cost of my recommended 8.61 percent original cost of equity capital and my 6.49 percent recommended cost of debt. My recommended 7.55 percent OCROR is 120 basis points lower than the Company-proposed unadjusted 8.75 percent weighted average cost of capital.

Fair Value Rate of Return – RUCO is recommending a 5.38 percent fair value rate of return ("FVROR") which is 217 basis points lower than my recommended 7.55 percent OCROR. In arriving at this 5.38 percent

FVROR figure RUCO considered a range of possible returns that could be applied to the Company's fair value rate base. The method that RUCO used to arrive at its recommended 5.38 percent FVROR comports with the provisions of Decision No. 70441, dated July 28, 2008, which resulted from a prior remand proceeding which involved Chaparral City Water Company.[2] The methodology that RUCO relied on to arrive at its recommended FVROR figure is explained fully in the testimony of RUCO witness Ralph Smith.

Q. Please explain why RUCO is recommending two different rates of return in this case?

A. UNSG Gas has chosen to use an average of the Company's original cost rate base ("OCRB"), which is based on the original book value of plant assets, and a rate base derived from a reconstruction cost new study ("RCND"), which takes general inflation into consideration, to arrive at a fair value rate base ("FVRB") which reflects the current dollar value of UNSG's original cost rate base. Because general inflation is also reflected in my OCROR figure, it is inappropriate to apply it to an OCRB. To do so would result in a double counting of inflation. For this reason RUCO has derived a FVROR which reduces my recommended OCROR by an inflation factor of 217 basis points.

[2] Chaparral City Water Company has appealed that Decision. The appeal is currently pending before the Arizona Court of Appeals.

Q. Can you explain further why it is necessary to determine an inflation factor adjustment to arrive at an OCROR?

A. Yes. Unless a utility elects to forego an RCND study that restates the value of the OCRB in current dollars, and agrees to use its OCRB as its FVRB, the utility's FVRB is calculated by averaging its OCRB and its RCND rate bases. Because an RCND study restates the OCRB in current dollars (through the use of engineering indexes that contain certain inflation factors to calculate an RCND rate base), it is inappropriate to apply an OCROR to a FVRB. This is because the OCROR, like the FVRB, contains an inflation component in it. Consequently, the application of the OCRB rate of return to a FVRB (calculated using the average of an OCRB and the RCND rate base) produces an inappropriate level of operating income which reflects an over-counting of the effects of inflation. As a result, a utility's investors would earn additional operating income on the effects of inflation, as opposed to only earning a return on actual investor supplied capital. To remedy this situation, the OCROR is adjusted downward by removing the inflation expectation that is embedded in it.[3] This is the same rationale that the Commission relied on in Decision No. 70441.

...

[3] In a case where there is deflation, an upward adjustment would be made to account for a level of deflation.

Q. Why do you believe that RUCO's recommended 5.38 percent FVROR is an appropriate rate of return for UNSG to earn on its invested capital?

A. The FVROR that RUCO is recommending meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

...

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as UNSG, 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 recommended cost of equity capital for UNSG?

A. Based on the results of my DCF and CAPM analyses, which ranged from 5.26 percent to 11.40 percent for a sample of local distribution companies ("LDC"), I am recommending an 8.61 percent original cost of equity capital for UNSG. My recommended original cost of equity capital figure represents an average of the results of my DCF and CAPM analyses, which utilized a sample of publicly traded natural gas local distribution companies ("LDC").

Discounted Cash Flow (DCF) Method

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

Q. In determining the rate of future dividend growth for UNSG, 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.[4]

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

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

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[5] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[6] 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.

[5] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[6] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

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.

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,[7] 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.

[7] 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 $[(M \div B) + 1] \div 2$.

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 $[(M \div B) + 1] \div 2$ 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[8], 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

[8] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on two separate proxy groups. A water company proxy group comprised of three publicly traded water companies and a natural gas proxy group consisting of ten natural gas local distribution companies ("LDC") that have similar operating characteristics to water providers.

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

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with UNSG itself. Consequently it was necessary to create a proxy by analyzing publicly traded water companies and LDC's with similar risk characteristics.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the companies that make up your proxy for UNSG?

A. All of the LDC's in my sample are publicly traded on the NYSE and are followed by <u>The Value Line Investment Survey's</u> ("Value Line") natural gas (distribution) industry segment. All of the companies in the proxy are engaged in the provision of regulated natural gas distribution services. Attachment A 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 proxy?

A. The ten natural gas LDC's included in my proxy (and their NYSE ticker symbols) are AGL Resources, Inc. ("AGL"), Atmos Energy Corp. ("ATO"), Laclede Group, Inc. ("LG"), New Jersey Resources Corporation ("NJR"), Nicor, Inc. ("GAS"), Northwest Natural Gas Co. ("NWN"), Piedmont Natural Gas Company ("PNY"), South Jersey Industries, Inc. ("SJI")

Southwest Gas Corporation ("SWX"), which is the dominant natural gas provider in Arizona, and WGL Holdings, Inc. ("WGL").

Q. Briefly describe the regions of the U.S. served by the ten natural gas LDC's that make up your sample proxy.

A. The ten LDC's listed above provide natural gas service to customers in the Middle Atlantic region (i.e. NJI which serves portions of northern New Jersey, SJI which serves southern New Jersey and WGL which serves the Washington D.C. metro area), the Southeast and South Central portions of the U.S. (i.e. AGL which serves Virginia, southern Tennessee and the Atlanta, Georgia area and PNY which serves customers in North Carolina, South Carolina and Tennessee), the South, deep South and Midwest (i.e. ATO which serves customers in Kentucky, Mississippi, Louisiana, Texas, Colorado and Kansas, GAS which provides service to northern and western Illinois, and LG which serves the St. Louis area), and the Pacific Northwest (i.e. NWN which serves Washington state and Oregon). Portions of Arizona, Nevada and California are served by SWX.

Q. Did the Company's witness also perform a similar analysis using natural gas LDC's?

A. Yes, the Company's witness, Kentton C. Grant, performed a similar analysis of publicly traded LDC's.

Q. Does your sample of LDC's include all of the same LDC's that Mr. Grant included in his sample?

A. Yes.

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the historical observation period 2004 to 2008. Schedule WAR-5 also includes Value Line's projected 2009, 2010 and 2012-14 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for the LDC's 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 AGL Resources, Inc., (NYSE symbol AGL) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on pages 9 and 10) to multiply AGL's earned return on common equity by its earnings retention ratio for each year during the 2004 to 2008 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, AGL's sustainable internal growth rate increased from 5.45% in 2004 to 6.14% in 2005. The company's growth rates experienced a pattern of decline during the remainder of the observation period, which resulted in a 5.49% average over the 2004 to 2008 time frame. Value Line's analysts are forecasting this trend to continue through 2009 before growth climbs steadily to 5.98% through the 2012-14 period. Based on these estimates I believe a 5.30% rate of internal growth is reasonable for AGL (Schedule WAR-4, Page 1, Column A, Line 1).

Q. Please continue with the external growth rate "s x v" component portion of your analysis.

A. Schedule WAR-5 demonstrates that AGL's share growth averaged just 0.07% over the observation period. Value Line expects future outstanding shares to increase from 76.90 million in 2008 to 85.00 million by the end of 2014. Taking this data into consideration, I am estimating a 1.75% rate of share growth for AGL (Schedule WAR-4, Page 2, Column A, Line 1). I used this estimate to calculate the s x v component of the DCF dividend growth rate. My final dividend growth rate estimate for AGL is 5.58

percent (5.30 percent internal growth + 0.28 percent external growth) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the sample natural gas utilities?

A. Based on the DCF model, my average dividend growth rate estimate is 6.45 percent, which is also displayed on page 1 of Schedule WAR-4.

Q. How do your average dividend growth rate estimates compare with the growth rate data published by Value Line and other analysts?

A. My 6.45 percent estimate is 14 basis points lower than the 6.59 percent consensus projections published by Zacks Investment Research ("Zacks"), exhibited in my Attachment B, and 12 basis points higher than Value Line's 4.33 percent projected estimates. As can also be seen on Schedule WAR-6, the 6.45 percent estimate that I have calculated is 77 basis points higher than the 5.68 percent five-year historical average of Value Line data (on EPS, DPS and BVPS) and is 123 basis point higher than the 5.22 percent average of the 5-year EPS means provided by Zacks, and the aforementioned percent five-year historical average of Value Line data. In fact, my 6.45 percent estimate is 383 basis points higher than the 2.62 percent Value Line 5-year compound history that is also displayed on Schedule WAR-6. Based on the information presented in Schedule WAR-6, I would say that my 6.45 percent estimate, which falls between Zack's and Value Line's projections, is a fair representation of the growth estimates presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's March 13, 2009 Ratings and Reports Natural Gas Utility update. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period March 30, 2009 to May 22, 2009.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the LDC's included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 11.40 percent.

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. 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.

[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.

Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\, ß\, (\, r_m - r_f\,)\,]$$

where:

k	=	the expected return of a given security,
r_f	=	risk-free rate of return,
$ß$	=	beta coefficient, a statistical measurement of a security's systematic risk,
r_m	=	average market return (e.g. S&P 500), and
$r_m - r_f$	=	market risk premium.

Q. What types of financial instruments are generally used as a proxy for the risk-free rate of return in the CAPM model?

A. Generally speaking, the yields of U.S. Treasury instruments are used by analysts as a proxy for the risk-free rate of return component.

...

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[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 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

[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.

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

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used an eight-week average of the yields on a 5-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated April 3, 2009 through May 22, 2009 (Attachment C). This resulted in a risk-free (r_f) rate of return of 1.87 percent.

Q. Why did you use the yield on a 5-year year U.S. Treasury instrument as opposed to a short-term T-Bill?

A. While a shorter term instrument, such as a 91-day T-Bill, presents the lowest possible total risk to an investor, a good argument can be made that the yield on an instrument that matches the investment period of the asset being analyzed in the CAPM model should be used as the risk-free rate of return. Since utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury Instrument closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect.

. . .

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical total returns on the S&P 500 index from 1926 to 2007 as the proxy for the market rate of return (r_m). For the risk-free portion of the risk premium component (r_f), I used the geometric mean of the total returns of long-term government bonds for the same eighty-one year period. The market risk premium (r_m - r_f) that results by using these inputs is 5.10 percent (10.40% - 5.30% = 5.10%). The market risk premium that results by using the arithmetic mean calculation is 6.80 percent (12.30% - 5.50% = 6.80%).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in both my proxies, were calculated by Value Line and were current as of March 13, 2009. 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 LDC's included in my sample ranged from 0.60 to 0.75 with an average beta of 0.67.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 5.26 percent. My calculation using an arithmetic mean results in an average expected return of 6.39 percent.

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	11.40%
CAPM	5.26% – 6.39%

Based on these results, my best estimate of an appropriate range for an original cost of equity capital for UNSG is 5.26 percent to 11.40 percent. My final recommended original cost of equity capital figure is 8.61 percent.

...

Q How did you arrive at your recommended original cost of equity capital figure of 8.61 percent?

A. My recommended original cost of equity capital figure of 8.61 percent is the average of my DCF and CAPM results. The calculation can be seen on Page 3 of Schedule WAR-1.

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

A. The 11.00 percent cost of equity capital proposed by the Company is 239 basis points higher than the 8.61 percent original cost of equity capital that I am recommending.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[12] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount

[12] 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.

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.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding a recession.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates – moves which indicated that the worst may be over and that the recession might have bottomed out during the last quarter of 2001 – a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in forty-five years.

Even though some signs of economic strength, mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.[13]"

[13] Wolk, Martin, "Fed holds interest rates steady," MSNBC, January 28, 2004.

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief.

As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What was the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the federal funds rate of 5.25 percent established on June 29, 2006.

Q. How did analysts view the Fed's actions between January 2001 and August 2006?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[14] In other words, the Fed was trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[15]

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[14] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[15] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings – like the one that the Fed managed to pull off during the 1994-95 time frame, in which a recession or a bear market were avoided – rarely happen[16]. Since it began increasing the federal funds rate in June 2004, the Fed had assured investors that it would increase rates at a "measured" pace. Many analysts and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[17]. According to Mr. Browning, at the time that his article was published, the hope was that Chairman Bernanke would succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

[16] Browning, E.S, "Not Too Fast, Not Too Slow…," The Wall Street Journal Online Edition, August 21, 2006.

[17] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

Q. Was the Fed's attempt to engineer a soft landing successful during the period that followed the August 8, 2006 FOMC meeting?

A. It would appear so. Articles published in the mainstream financial press were generally upbeat on the economy during that period. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low; wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[18]

Q. What has been the state of the economy over the past two years?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate

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

unchanged at 5.25 percent.[19] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crisis rooted in a deterioration of the market for subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through open market operations) into the credit markets.[20] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal,[21] 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.

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

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

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

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points (25 basis points more than what was anticipated). This brought the federal funds rate down to a level of 4.75 percent. The Fed's action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175 basis points to a level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

Q. What actions has the Fed taken in regard to interest rates over the past year?

A. The Fed made two more rate cuts which included a 75 basis point reduction in the federal funds rate on March 18, 2008 and an additional 25 basis point reduction on April 30, 2008. The Fed's decision to cut rates was based on its belief that the slowing economy was a greater concern than the current rate of inflation (which the majority of FOMC members believed would moderate during the economic slowdown).[22] 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[23]. Amidst this turmoil, the Fed made the decision to cut the federal funds rate by another 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. After FOMC meetings in January, March and April of 2009, the Fed elected not to make any changes in the federal funds rate, stating in January that the

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

[23] Soloman, Deborah, Michael R. Crittenden and Damian Paletta, "U.S. Bailout Plan Calms Markets, But Struggle Looms Over Details" The Wall Street Journal, September 20, 2008

rate would remain low "for some time."[24] Presently, the Fed's discount rate is at 0.50 percent, a level not seen since 1940s.[25] Based on data released during the early part of December 2008, the U.S. is now officially in a recession which began in December of 2007.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected benchmark rates?

A. U.S. Treasury instruments are for the most part still at historically low levels. The Fed's actions have also had the overall effect of reducing the cost of many types of business and consumer loans. As can be seen in Schedule WAR-8, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has fallen to 0.50 percent from 2.25 percent in 2008.

Q. What has been the trend in other leading interest rates over the last year?

A. As of May 13, 2009, the leading interest rates have all dropped from the levels that existed a year ago (Attachment C, Value Line Selection & Opinion page 3529). The prime rate has fallen from 5.00 percent a year ago to 3.25 percent. The benchmark federal funds rate, just discussed, has decreased from 2.00 percent, in May 2008, to a level of 0.25 percent

[24] Hilsenrath, Jon and Liz Rappaport, "Fed Weighs Idea of Buying Treasurys as Focus Shifts" The Wall Street Journal, January 29, 2009

[25] Hilsenrath, Jon, "Fed Cuts Rates Near Zero to Battle Slump" The Wall Street Journal, December 17, 2008

(as a result of the December 16, 2008 rate cut discussed above). The yields on all of the non-inflation protected maturities of U.S. Treasury instruments exhibited in my Attachment C have also decreased over the past year. A previous trend, described by former Chairman Greenspan as a "conundrum"[26], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, is completely reversed and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists (Attachment C). The 5-year Treasury yield, used in my CAPM analysis, has fallen from 3.20 percent, in May 2008, to 1.98 percent as of May 13, 2009. The 30-Year Treasury constant maturity rate also decreased from 4.61 percent over the past year to 4.10 percent. These current yields are considerably lower than corresponding yields that existed during the early nineties and at the beginning of the current decade (as can be seen on Schedule WAR-8).

Q. What is the current outlook for the economy?

A. Value Line's analysts have become more optimistic in their outlook on the economy as of late and had this to say in their Quarterly Economic Review that appeared in the May 29, 2009 edition of Value Line's Selection and Opinion publication:

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

> **We probably have seen the low point in the business cycle,** with the six month period from early last fall through late this winter likely having marked that trough. The business outlook, which deteriorated steadily during this time—with housing, auto demand, retail sales, manufacturing, and on manufacturing all slumping in tandem— has grown less troubling in recent weeks. The lessening in the recession's clout suggests that the U.S. gross domestic product, which fell 6.3% in the fourth quarter of 2008 and by 6.1% in the opening period of this year, will decline by less than half that amount in the quarter that ends on June 30th. It should be noted that the surveys being issued largely detail a reduction in the economic downturn's severity, rather than any appreciable pickup in strength. In our view, we are still months away from a sustained business upturn. The best that seems ahead in the next 12 to 18 months is an uneven and understated recovery, with quarterly growth only gradually rising above 2%. We think it will be late 2010 or early 2011 before the economy really gets rolling.

Q. What is Value Line's outlook for interest rates?

A. In the Selection and Opinion publication noted above, Value Line's analysts had this to say:

> **Interest Rates:** Late last year, with the threat of a deepening recession, or worse, increasing by the day, the Federal Reserve voted to lower the Federal Funds rate (the rate charged on overnight loans between banks) to near zero. That is where they remain now and are likely to stay for a year or more. Other short-term interest rates — notably on three-and six-month Treasury bills — remain negligible, as do yields on money market funds and bank certificates of deposit of short duration. Longer-term fixed-income instruments (i.e., 10-year Treasury notes and 30-year Treasury bonds), where yields are more closely tied to long-range inflationary expectations, are also low by recent standards, at 3.2% and 4.2%, respectively. Here, though, yields are trending higher, as some market forecasters opine that inflation will pose a problem later in the pending business recovery. Time will tell if such worries are justified. Long-term interest rates are not yet serious competition for stocks, but they could become so with even a moderate further increase.

Q. What is Value Line's opinion on the current rate of inflation?

A. Also in the Selection and Opinion publication noted above, Value Line's analysts had this to say:

> **Inflation:** The major story here has been the ratcheting down of inflation since late last year, when declining global economic activity and plunging oil prices helped bring about selective deflation, or falling prices. Producer (wholesale) and consumer prices fell further during the opening quarter of 2009, albeit less sharply than in the preceding three months, as demand for labor, raw materials, and energy all contracted. The threat of deflation now seems to be lessening, as the decline in economic activity slows. Our sense is that aggregate price changes will be limited in the second quarter of this year and that inflation will start to selectively edge higher by the fourth quarter. Somewhat higher producer and consumer prices are likely in 2010. We think it will be 2011 or 2012, before there is much chance of an inflation problem.

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

A. Natural gas utilities appear to be doing well and represent a safe investment according to Value Line analyst Richard Gallagher. In the March 13, 2009 quarterly update on the natural gas industry Mr. Gallagher stated the following:

> The Natural Gas Utility Industry has performed well in recent months. This is impressive given the weak economy and a tough regulatory environment. Despite these challenges, companies in this sector continue to deliver solid results and represent a relatively safe option amid the turmoil in the world's financial markets. As a result, this group has risen near the top of our industry spectrum.

Mr. Gallagher went on to state:

> The global economy continues to struggle. Tight credit and a slumping real estate market are among the main factors contributing to the recessionary environment. Furthermore, these conditions continue to weigh on results in this sector. Indeed, usage continues to decline as customers have become more cost conscious. Moreover, bill collection has become increasingly difficult as unemployment and foreclosures continue to rise. Despite the aforementioned conditions, investors should note that this group is an interesting defensive play. While these factors will likely continue to impact the utilities, this industry should perform well compared to the rest of the market in the months ahead. Natural Gas Utilities generally have solid balance sheets and predictable cash flows, which is appealing given the weakness in the economy.

Mr. Gallagher concluded:

> The Natural Gas Utility sector has climbed near the top of our industry spectrum in recent months. Indeed, it features numerous timely stocks. In fact, UGI holds our highest rank (1) for Timeliness. However, various other companies are ranked to outperform the market over the coming six to 12 months. What's more, the majority of the equities in this industry offer above-average yields. Most notably, Nicor, AGL Resources and Atmos Energy all offer attractive payouts supported by steady cash flows. Therefore, investors looking for a good play in the year ahead should consider some of the names in this group.

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

A. I believe that my recommended cost of equity will provide UNSG with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are still low by historical standards) and a low and stable outlook for inflation 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 DCF analysis has produced such a return.

COST OF DEBT

Q. Have you reviewed UNSG's testimony on the Company-proposed cost of long-term debt?

A. Yes, I have reviewed the testimony prepared by Mr. Grant.

Q. Do you agree with Mr. Grant's inclusion of the amortized debt discount and expenses and losses attributed to reacquired debt and the credit facility fees to arrive at his final cost of debt figure of 6.49 percent?

A. Yes.

Q. What cost of long-term debt are you recommending for UNSG?

A. I am recommending that the Commission adopt the Company proposed cost of debt of 6.49 percent.

CAPITAL STRUCTURE

Q. Have you reviewed UNSG'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 that the Commission adopt the Company's actual test year capital structure comprised of 50.01 percent long-term debt and 49.99 percent common equity.

Q. What capital structure are you proposing for UNSG?

A. I am also recommending that the Commission adopt the Company's actual test year capital structure comprised of 50.01 percent long-term debt and 49.99 percent common equity.

Q. Is UNSG's actual capital structure in line with industry averages?

A. For the most part yes. UNSG's actual test year capital structure is very close to the capital structures of the LDC's included in my cost of capital analysis. As can be seen in Schedule WAR-9, the capital structures for those utilities averaged approximately 46 percent for debt and 54 percent for equity (53.4 percent common equity + 0.7 percent preferred equity).

WEIGHTED COST OF CAPITAL

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

A. The Company has proposed an unadjusted weighted average cost of capital of 8.75 percent. This composite figure is the result of a weighted average of UNSG's proposed 6.49 percent cost of long-term debt and 11.00 percent cost of common equity. The Company-proposed 8.75 percent OCRB weighted cost of capital is 120 basis points higher than the 7.55 percent OCRB weighted cost that I am recommending which is the weighted cost of my recommended 6.49 percent cost of long-term debt and my recommended 8.61 percent cost of common equity. In its Application, the Company makes a 79 basis point upward adjustment to the aforementioned 8.75 percent weighted average cost of capital in order to arrive at a 9.54 percent OCROR that produces the same level of operating income as the Company-proposed 6.80 percent FVROR does.

Q. How does the Company's proposed FVROR of 6.80 percent compare with RUCO's recommendation?

A. The Company has proposed a FVROR of 6.80 percent which is 142 basis points higher than the 5.38 percent FVROR that RUCO is recommending.

Q. Why is RUCO recommending a FVROR that is lower than the OCROR that was derived from the results of your DCF and CAPM analyses?

A. As I explained earlier in my testimony, the lower FVROR removes an inflation expectation that is embedded in the OCROR. The method that RUCO has relied on to arrive at its recommended 5.38 percent FVROR is consistent with the provisions contained in Decision No. 70441 which established a FVROR for Chaparral City Water Company ("Remand Proceeding"). During the Remand Proceeding, the Commission was required to develop an appropriate rate of return on Chaparral's FVRB under a remand order from the Arizona Court of Appeals. In doing so, the Commission adopted, in part, a methodology that was proposed by Ben Johnson, Ph.D., an expert witness who testified on behalf of RUCO on the FVRB rate of return issue that was central to that proceeding.[27]

[27] On September 30, 2005, the Commission issued Decision No. 68176 which granted a permanent rate increase to Chaparral. Following the Commission's decision on the matter, the Company filed an application for rehearing on which the Commission took no action. Chaparral subsequently filed an appeal with the Arizona Court of Appeals, Division One ("Court of Appeals"). The Company's appeal claimed that Chaparral was denied a fair rate of return on its invested capital as a result of the Commission's established method of calculating a level of operating income based on the Company's fair value rate base ("FVRB"). On February 13, 2007, the Court of Appeals issued a Memorandum Decision which affirmed in part, vacated, and remanded Decision No. 68176 to the Commission for further determination.

Q. What did Dr. Johnson recommend in the Remand Proceeding?

A. Dr. Johnson recommended that a 200 basis point adjustment be made to the original weighted average cost of capital in order to remove the effects of general inflation from Chaparrals FVRRB. His recommendation was based on the low end of a range of figures that represented the difference between Treasury Inflation-Protected Securities ("TIPS") and U.S. Treasury bonds with similar liquidity and maturity characteristics.

Q. Did the Commission adopt Dr. Johnson's recommendation?

A. In part, yes. The Commission adopted a FVROR that was derived from a an inflation adjustment that reduced the cost of common equity by 200 basis points as opposed Dr. Johnson's recommendation to reduce the original weighted average cost of capital by 200 basis points.

Q. Have you calculated a similar inflation adjustment in this case?

A. Yes.

Q. How did you calculate your inflation adjustment?

A. I relied on the same data sets of information that Dr. Johnson used to develop his inflation factor adjustment during the Remand Proceeding (Schedule WAR-1, Page 4 of 4). Since there was virtually no change in the average of the data – which compared TIP's and U.S. Treasury bonds with similar liquidity and maturity characteristics, I am recommending that a 250 basis point adjustment be used to arrive at an appropriate FVROR for UNSG .

COMMENTS ON UNSG'S COST OF EQUITY CAPITAL TESTIMONY

Q. What methods did Mr. Grant use to arrive at his cost of common equity for UNSG?

A. Mr. Grant used a DCF methodology and a CAPM methodology to estimate UNSG's cost of common equity. He also relied on a bond yield plus risk premium approach.

Q. Can you provide a comparison of the results derived from your respective DCF and CAPM models?

A. Yes.

DCF Comparison

Q. Were there any differences in the way that you conducted your DCF analysis and the way that Mr. Grant conducted his?

A. Yes, Mr. Grant relied on the results of a multi-stage DCF model, using the proxy of ten LDC's that I described earlier in my testimony, as opposed to the single-stage constant growth model that I relied on. Mr. Grant stated that his decision to rely solely on the multi-stage model was based on his belief that the single-stage constant growth model cannot be applied to companies having expected near-term growth rates that are significantly higher or lower than their long-term growth potential.

Q. Do you agree with Mr. Grant's rationale for not relying on the single-stage DCF model?

A. No. The long-term growth rate that Mr. Grant uses in the second stage of his multi-stage DCF model is a 6.30 percent figure that is the sum of a 3.40 percent average of real economic growth from 1929 through 2007, and 2.90 percent expected rate of inflation. The use of such a growth estimate assumes that the long-term growth rate for the natural gas utilities in his sample will be a combination of analysts' long-term growth rate projections and the growth rate of all goods and services produced by labor and property in the U.S. adjusted for inflation. A good argument can be made that more emphasis should be placed on the near-term component of Mr. Grant's multi-stage DCF model as opposed to the long-term growth rate that is carried out into perpetuity.

Q. Why didn't you conduct a multi-stage DCF analysis like the one conducted by Mr. Grant?

A. Primarily because the growth rate component that I estimated for my single-stage model already takes into consideration both a near-term and a 5-year long-term growth rate projection that are specific to the LDC's included in my proxy. As with the use of a 5-year treasury instrument for the risk free rate of return in my CAPM model, this 5-year investment horizon is very close to the 3 to 5-year periods that utilities in Arizona apply for rate relief.

Q. What is the difference between Mr. Grant's DCF estimate and your DCF estimate?

A. Mr. Grant's DCF high and low estimates, derived from his multi-stage model, of 9.50 percent and 11.20 percent are 190 to 20 basis points lower than the 11.40 percent cost of common equity derived from my DCF analysis which is a mean average of the DCF estimates of the ten LDC's in my proxy.

Q. Does Mr. Grant provide an estimate that is based on the single-stage model that you employed?

A. Not directly, however the exhibits contained in his testimony contain inputs and estimates used in his multi-stage model that can also be used in the single-stage model. Using the inputs and estimates that appear in Mr. Grant's exhibits, a single-stage model would produce a mean average estimate of 9.17 percent or 223 basis points lower than my 11.40 percent estimate. Using Mr. Grant's same 5-year DCF growth estimates for each of the LDC's in our sample, and substituting his dividend and stock price inputs with more recent data that I relied on, produces a mean average estimate of 10.18 percent which is 122 basis points lower than my single-stage DCF estimate.

Q. Have there been any changes in closing stock prices since Mr. Grant filed his direct testimony?

A. Yes. The stock prices for the LDC's used in our proxies have fallen since Mr. Grant filed his direct testimony, thus producing higher dividend yields. The difference between the average closing stock prices used in my analysis and Mr. Grant's analysis are as follows:

	Rigsby	Grant	Difference
AGL	$28.35	$32.85	-$4.50
ATO	$23.79	$26.75	-$2.96
LG	$34.89	$44.93	-$10.04
NJR	$32.51	$34.96	-$2.45
GAS	$32.52	$43.60	-$11.08
NWN	$41.80	$46.95	-$5.15
PNY	$24.50	$28.07	-$3.57
SJI	$34.87	$34.91	-$0.04
SWX	$20.23	$29.26	-$9.03
WGL	$30.85	$32.74	-$1.89

...

The differences in our respective dividend yields are as follows:

	Rigsby	Grant	Basis Point Difference
AGL	6.07%	5.27%	80
ATO	5.55%	5.08%	46
LG	4.41%	3.45%	96
NJR	3.81%	3.32%	50
GAS	5.72%	4.27%	145
NWN	3.78%	3.39%	39
PNY	4.42%	3.81%	43
SJI	6.51%	3.24%	327
SWX	4.70%	3.18%	152
WGL	4.67%	4.43%	24

Based on this information it is fair to say that a single stage model using updated stock prices, while holding Mr. Grant's other DCF growth component estimates constant, would produce a lower single-stage DCF estimate than the one that I have calculated.

CAPM Comparison

Q. Please describe the differences in the way that you conducted your CAPM analysis and the way that Mr. Grant conducted his?

A. The main difference between Mr. Grant's CAPM analysis and mine is that he relied solely on an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2007 as the proxy for the market rate of return (i.e. r_m) in order to arrive at his market risk premium (i.e. r_m - r_f) in his CAPM model. His 7.10 percent market risk premium, based on an arithmetic mean, is 30 basis points higher than the 6.80 percent market risk premium which I obtained from Morningstar data.

Q. What financial instrument did Mr. Grant use as a proxy for the risk free (i.e. r_f) rate in his CAPM model?

A. Mr. Grant used the yield to maturity on a 20-year U.S. Treasury instrument, which was 4.53 percent around the time that his direct testimony was filed in November 2008.

Q. What is the current yield on a 20-year U.S. Treasury bond?

A. As of the week ended May 22, 2007 the yield on a 20-year U.S. Treasury bond was 4.22 percent.

...

Q. Do you agree with Mr. Grant's use of a 20-year Treasury rate as the risk free proxy in the CAPM model?

A. No. As I stated earlier in my testimony, I believe that a 5-year instrument is more appropriate given the fact that utility rates are generally in effect for a 3 to 5-tear time frame.

Q. Did Mr. Grant use the same Value Line betas that you used in your CAPM analysis?

A. Yes. However Value Line's betas for the LDC's in our proxies have decreased since Mr. Grant filed his direct testimony. The mean average of the Value Line betas used by Mr. Grant is 0.87 as opposed to my average beta of 0.67, which was current as of March 13, 2009.

Q. What is the difference between Mr. Grant's CAPM estimate and your CAPM estimate?

A. Mr. Grant's CAPM estimate, derived from his arithmetic mean model, of 10.70 percent is 431 basis points higher than the 6.39 percent cost of common equity derived from my arithmetic mean CAPM analysis and 544 basis points higher than my 5.26 percent cost of common equity derived from my geometric mean CAPM analysis. Updating Mr. Grant's risk free rate of return and beta inputs in his CAPM model would produce an expected return of 8.98, which is 172 basis points lower than the 10.70 percent figure presented in his testimony.

Final Cost of Equity Estimate

Q. How did Mr. Grant arrive at his proposed 11.00 percent cost of common equity for UNSG?

A. Mr. Grant used his own judgment to arrive at his proposed 11.00 percent cost of equity capital which is based on the results of his DCF, CAPM and risk premium analyses. He also compared UNSG's credit rating with the bond ratings of A-rated and Baa-rated utilities.

Q. How did Mr. Grant arrive at his proposed 6.80 percent fair value rate of return?

A. Mr. Grant again relied on his own judgment and stated that the 6.80 percent fair value rate of return was lower than the results he obtained by using the method that I relied on, which was adopted in Decision No. 70441 (and another method proposed by ACC Staff), and would produce an operating income of $256 million. According to Mr. Grant, this is the level of income needed to provide UNSG's with the ability to earn its cost of capital, maintain creditworthiness and attract capital.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Grant or any other witness for UNSG constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on UNSG?

A. Yes, it does.

Qualifications of William A. Rigsby, CRRA

EDUCATION:

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

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

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

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

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

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

EXPERIENCE:

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

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

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

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

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

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

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

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

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

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

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

ATTACHMENT A

INDUSTRY TIMELINESS: 5 (of 99)

The Natural Gas Utility Industry has performed well in recent months. This is impressive given the weak economy and a tough regulatory environment. Despite these challenges, companies in this sector continue to deliver solid results and represent a relatively safe option amid the turmoil in the world's financial markets. As a result, this group has risen near the top of our industry spectrum.

Economic Environment

The global economy continues to struggle. Tight credit and a slumping real estate market are among the main factors contributing to the recessionary environment. Furthermore, these conditions continue to weigh on results in this sector. Indeed, usage continues to decline as customers have become more cost conscious. Moreover, bill collection has become increasingly difficult as unemployment and foreclosures continue to rise. Despite the aforementioned conditions, investors should note that this group is an interesting defensive play. While these factors will likely continue to impact the utilities, this industry should perform well compared to the rest of the market in the months ahead. Natural Gas Utilities generally have solid balance sheets and predictable cash flows, which is appealing given the weakness in the economy.

Regulation

This group is regulated by state commissions that dictate the return on equity these utilities can achieve. Consequently, the regulatory environment has a heavy bearing on each individual company's results. If a utility does not have ample relief, its budget can become strained. As a result, a company's infrastructure can age and profitability can decline. On the other hand, a favorable ruling can position a utility to register steady gains and allow it to build its infrastructure. Therefore, rate cases remain the main theme in this sector. On point, numerous companies currently have rate cases pending. *Southwest Gas, Nicor, AGL Resources* are all awaiting decisions, which should drive their performance going forward. Moreover, energy efficiency will likely become an increasingly important factor in these decisions given the new administration in the White House. As the United States moves in this direction, utilities that embrace energy conservation measures may benefit from a more favorable regulatory environment.

Nonregulated Ventures

A strategy that is becoming increasingly common is nonregulated ventures. These opportunities allow companies to diversify their operations and gain income that is not subject to the state regulatory commissions. These businesses currently make up only a small portion of this sector's profits but will likely become a more important opportunity in the years ahead.

Weather

The peak heating season is just about coming to an end. This period is when these utilities have their best opportunity to post strong results on the bottom line. Looking ahead, these companies will likely turn their attention to strengthening their operations and better managing their costs as we move toward the summer months.

Weather abnormalities can hurt results. Many of these businesses have weather-adjusted rate mechanisms that are used to hedge the risk of unseasonable weather. Thus, investors should keep an eye out for utilities that rely on this strategy since they usually have a relatively steady performance.

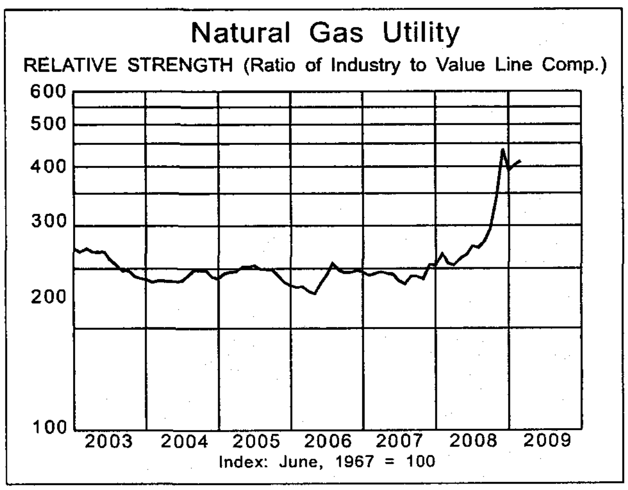
Conclusion

The Natural Gas Utility sector has climbed near the top of our industry spectrum in recent months. Indeed, it features numerous timely stocks. In fact, *UGI* holds our highest rank (1) for Timeliness. However, various other companies are ranked to outperform the market over the coming six to 12 months. What's more, the majority of the equities in this industry offer above-average yields. Most notably, *Nicor, AGL Resources* and *Atmos Energy* all offer attractive payouts supported by steady cash flows. Therefore, investors looking for a good play in the year ahead should consider some of the names in this group.

Richard Gallagher

Composite Statistics: Natural Gas Utility

2005	2006	2007	2008	2009	2010		12-14
36075	38273	38528	*40000*	*41500*	*42750*	Revenues ($mill)	*51250*
1386.0	1553.3	1562.4	*1650*	*1725*	*1800*	Net Profit ($mill)	*2150*
36.0%	35.3%	33.9%	*36.0%*	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
3.8%	4.0%	4.1%	*4.1%*	*4.2%*	*4.2%*	Net Profit Margin	*4.2%*
51.3%	51.2%	50.4%	*51.0%*	*51.0%*	*51.0%*	Long-Term Debt Ratio	*52.0%*
48.4%	48.7%	49.5%	*48.0%*	*48.0%*	*48.0%*	Common Equity Ratio	*46.0%*
29218	30847	32263	*33750*	*33250*	*34750*	Total Capital ($mill)	*40000*
30894	32543	33936	*35250*	*36750*	*38500*	Net Plant ($mill)	*46250*
6.5%	6.6%	6.5%	*6.5%*	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
9.7%	10.2%	9.8%	*10.0%*	*10.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.8%	10.2%	9.8%	*10.0%*	*10.0%*	*10.5%*	Return on Com Equity	*11.0%*
3.5%	4.0%	3.7%	*4.0%*	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
65%	61%	62%	*63%*	*63%*	*64%*	All Div'ds to Net Prof	*65%*
17.1	15.6	16.6		*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.0*
.91	.84	.88				Relative P/E Ratio	*.85*
3.8%	3.9%	3.7%				Avg Ann'l Div'd Yield	*4.6%*
315%	327%	336%	*350%*	*375%*	*375%*	Fixed Charge Coverage	*400%*



AGL RESOURCES NYSE-AGL

RECENT PRICE	25.92	P/E RATIO	9.2 (Trailing: 9.2; Median: 14.0)	RELATIVE P/E RATIO	0.89	DIV'D YLD	6.7%	VALUE LINE

TIMELINESS **2** Raised 2/13/09

SAFETY **2** New 7/27/90

TECHNICAL **2** Raised 3/6/09

BETA .75 (1.00 = Market)

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+110%)	24%
Low	40	(+55%)	16%

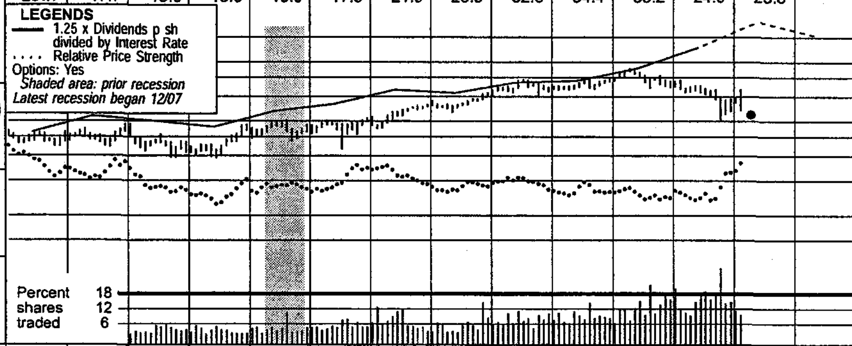
Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	3	0	0	1	0	0	2	1
to Sell	0	2	0	0	1	0	0	3	1

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	105	131	92
to Sell	127	106	130
Hld's(000)	47696	46762	48796

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	23.4	23.4	23.2	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1	34.9
Low:	17.7	15.6	15.5	19.0	17.3	21.9	26.5	32.0	34.4	35.2	24.0	25.8



Target Price Range

2012	2013	2014
64	48	40
32	24	20
16	12	8
6		

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-15.7	-44.9
3 yr.	-11.5	-44.1
5 yr.	19.7	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
22.73	23.59	19.32	21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	***35.90***	***36.40***	Revenues per sh A	***39.40***
2.25	2.24	2.33	2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	***4.70***	***4.85***	"Cash Flow" per sh	***5.30***
1.08	1.17	1.33	1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	***2.70***	***2.85***	Earnings per sh A B	***3.20***
1.04	1.04	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	***1.72***	***1.76***	Div'ds Decl'd per sh C■	***1.88***
2.49	2.37	2.17	2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	***4.35***	***4.30***	Cap'l Spending per sh	***5.00***
9.90	10.19	10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	***21.55***	***21.85***	Book Value per sh D	***21.75***
49.72	50.86	55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	***78.00***	***79.00***	Common Shs Outst'g E	***85.00***
17.9	15.1	12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***15.0***
1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.76			Relative P/E Ratio	***1.00***
5.4%	5.9%	6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%			Avg Ann'l Div'd Yield	***3.9%***

CAPITAL STRUCTURE as of 12/31/08
Total Debt $2541.0 mill. **Due in 5 Yrs** $1410 mill.
LT Debt $1675.0 mill. **LT Interest** $80.0 mill.
(Total interest coverage: 4.0x)

Leases, Uncapitalized Annual rentals $30.0 mill.
Pension Assets-12/08 $242.0 mill. **Oblig.** $442.0 mill.

Pfd Stock None

Common Stock 76,902,777 shs.
as of 1/30/09
MARKET CAP: $2.0 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
1068.6	607.4	1049.3	868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	***2800***	***2875***	Revenues ($mill) A	***3350***
52.1	71.1	82.3	103.0	132.4	153.0	193.0	212.0	211.0	207.6	***210***	***225***	Net Profit ($mill)	***270***
33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	38.9%	***38.0%***	***38.0%***	Income Tax Rate	***38.0%***
4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	***7.5%***	***7.8%***	Net Profit Margin	***8.1%***
45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	***50.0%***	***46.5%***	Long-Term Debt Ratio	***45.0%***
49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	***50.0%***	***53.5%***	Common Equity Ratio	***55.0%***
1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	***3355***	***3225***	Total Capital ($mill)	***3350***
1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	***3950***	***4100***	Net Plant ($mill)	***4400***
5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	7.5%	***7.5%***	***8.0%***	Return on Total Cap'l	***9.0%***
7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	***12.5%***	***13.0%***	Return on Shr. Equity	***14.5%***
7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	***12.5%***	***13.0%***	Return on Com Equity	***14.5%***
NMF	3.2%	4.2%	7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	5.0%	***4.5%***	***5.0%***	Retained to Com Eq	***6.0%***
101%	72%	65%	52%	53%	49%	52%	52%	58%	60%	***64%***	***62%***	All Div'ds to Net Prof	***59%***

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	20.0	21.0	16.0
Other	1802.0	1790.0	2026.0
Current Assets	1822.0	1811.0	2042.0
Accts Payable	213.0	172.0	202.0
Debt Due	539.0	580.0	866.0
Other	875.0	893.0	915.0
Current Liab.	1627.0	1645.0	1983.0
Fix. Chg. Cov.	397%	391%	416%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	4.5%	17.5%	*2.5%*
"Cash Flow"	6.5%	7.0%	*2.5%*
Earnings	7.0%	11.5%	*3.0%*
Dividends	3.5%	6.5%	*2.5%*
Book Value	7.0%	11.5%	*.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1044	436	434	707	2621
2007	973	467	369	685	2494
2008	1012	444	539	805	2800
2009	***1030***	***490***	***505***	***775***	***2800***
2010	***1045***	***505***	***520***	***805***	***2875***

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.41	.25	.46	.60	2.72
2007	1.29	.40	.17	.86	2.72
2008	1.16	.30	.28	.97	2.71
2009	***1.20***	***.35***	***.30***	***.85***	***2.70***
2010	***1.25***	***.35***	***.35***	***.90***	***2.85***

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.31	.31	.31	.37	1.30
2006	.37	.37	.37	.37	1.48
2007	.41	.41	.41	.41	1.64
2008	.42	.42	.42	.42	1.68
2009	.43				

BUSINESS: AGL Resources, Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, and Virginia Natural Gas. The utilities have more than 2.2 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Maryland. Engaged in nonregulated natural gas marketing and other allied services. Also wholesales and retails propane. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. Officers/directors own less than 1.0% of common (3/08 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

Shares of AGL Resources have held up better than the broader market over the past six months. That's owing to the steadiness of its underlying operations. Share net roughly equaled the tally reached in the prior two years. In 2008, healthy performances at the Wholesale Services and Energy Investments units were roughly offset by lower operating earnings at the Distribution and Retail Energy businesses. (Note: AGL is the stock's new ticker symbol).

The economic environment should remain challenging in the current year. Slower customer growth ought to hinder results at the company's utility operations. Moreover, we expect higher development and maintenance costs and a return to a more normal earnings level at the Wholesale Services business. Overall, AGL anticipates share net of $2.65-$2.75 for 2009, assuming normal weather patterns. Our estimate lies at the midpoint of this range. Bottom-line growth may well resume in 2010, assuming success at obtaining rate relief (discussed below).

The company is seeking higher rates. It will have four rate cases in the next two years, beginning with a filing in New Jersey. AGL's focus on procuring rate relief is encouraging, as the company depends upon such approved revenue increases to cope with higher costs and compensate it for investments made in its utility operations. Still, what pressures the rate boards may face remain unclear.

The board of directors has recently approved a modest dividend increase. Starting with the March payout, the quarterly dividend will now be $0.43. A modest increase makes sense, given stalled earnings growth and a lower cash balance in recent times. Slow, but steady, dividend growth will likely continue at AGL in the coming years.

This issue has good appeal at present. The shares have improved a notch in Timeliness since our December review, and are now ranked 2 (Above Average). Moreover, AGL earns high marks for Safety, Price Stability, and Earnings Predictability. In addition, the stock's healthy dividend yield should appeal to income investors. Overall, this equity offers attractive total return potential for a utility.

Michael Napoli, CPA *March 13, 2009*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, ($0.83); '99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late April. (C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2008: $418 million, $5.44/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE	20.24	P/E RATIO	9.6 (Trailing: 10.0; Median: 16.0)	RELATIVE P/E RATIO	0.93	DIV'D YLD	6.6%	VALUE LINE

TIMELINESS 2 Raised 12/12/08
SAFETY 2 Raised 12/16/05
TECHNICAL 2 Raised 3/13/09
BETA .60 (1.00 = Market)

High:	32.3	33.0	26.3	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3	26.2
Low:	24.8	19.6	14.3	19.5	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.2

2012-14 PROJECTIONS

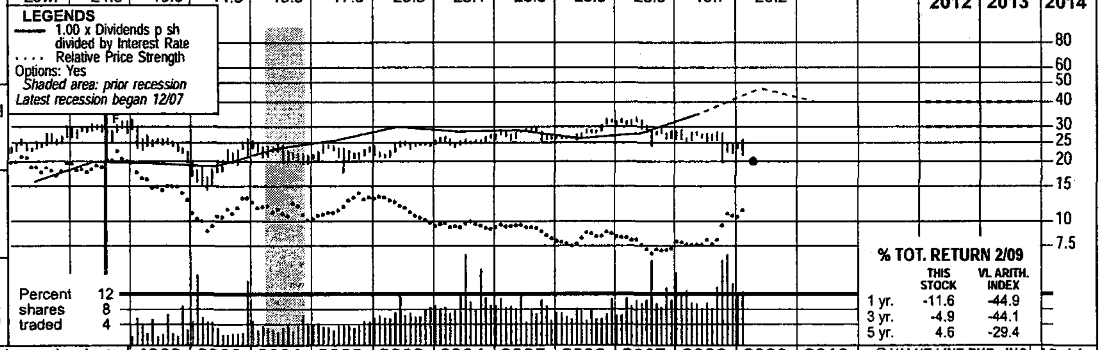
	Price	Gain	Ann'l Total Return
High	40	(+100%)	23%
Low	30	(+50%)	15%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	3	0	1	1	0	1	1

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	112	119	103
to Sell	103	89	119
Hld's(000)	58504	58318	56301



% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-11.6	-44.9
3 yr.	-4.9	-44.1
5 yr.	4.6	-29.4

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
22.09	26.61	35.36	22.82	54.39	46.50	61.75	75.27	66.03	79.52	*82.60*	*84.95*	Revenues per sh A	*94.55*
2.62	3.01	3.03	3.39	3.23	2.91	3.90	4.26	4.14	4.19	*4.35*	*4.40*	"Cash Flow" per sh	*4.80*
.81	1.03	1.47	1.45	1.71	1.58	1.72	2.00	1.94	2.00	*2.10*	*2.15*	Earnings per sh A B	*2.50*
1.10	1.14	1.16	1.18	1.20	1.22	1.24	1.26	1.28	1.30	*1.32*	*1.34*	Div'ds Decl'd per sh C ■	*1.40*
3.53	2.36	2.77	3.17	3.10	3.03	4.14	5.20	4.39	5.20	*5.50*	*5.75*	Cap'l Spending per sh	*6.60*
12.09	12.28	14.31	13.75	16.66	18.05	19.90	20.16	22.01	22.60	*24.05*	*24.70*	Book Value per sh	*26.90*
31.25	31.95	40.79	41.68	51.48	62.80	80.54	81.74	89.33	90.81	*92.00*	*93.00*	Common Shs Outst'g D	*110.00*
33.0	18.9	15.6	15.2	13.4	15.9	16.1	13.5	15.9	13.6	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
1.88	1.23	.80	.83	.76	.84	.86	.73	.84	.84	*Value Line*		Relative P/E Ratio	*.95*
4.1%	5.9%	5.1%	5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*
690.2	850.2	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	*7600*	*7900*	Revenues ($mill) A	*10400*
25.0	32.2	56.1	59.7	79.5	86.2	135.8	162.3	170.5	180.3	*195*	*200*	Net Profit ($mill)	*275*
35.0%	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	*39.0%*	*39.0%*	Income Tax Rate	*40.5%*
3.6%	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	*2.6%*	*2.5%*	Net Profit Margin	*2.6%*
50.0%	48.1%	54.3%	53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	*48.5%*	*48.0%*	Long-Term Debt Ratio	*49.0%*
50.0%	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	*51.5%*	*52.0%*	Common Equity Ratio	*51.0%*
755.1	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	*4300*	*4415*	Total Capital ($mill)	*5800*
965.8	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	*4350*	*4560*	Net Plant ($mill)	*5850*
5.1%	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	*9.0%*	*8.5%*	Return on Shr. Equity	*9.5%*
6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	*9.0%*	*8.5%*	Return on Com Equity	*9.5%*
NMF	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
NMF	112%	79%	82%	70%	77%	73%	63%	65%	65%	*62%*	*62%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $2481.2 mill. **Due in 5 Yrs** $1360.0 mill.
LT Debt $1719.9 mill. **LT Interest** $105.0 mill.
(LT interest earned: 2.9x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $18.4 mill.
Pfd Stock None
Pension Assets-9/08 $341.4 mill. **Oblig.** $337.6 mill.
Common Stock 91,634,602 shs. **as of 1/27/09**
MARKET CAP: $1.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	12/31/08
Cash Assets	60.7	46.7	69.8
Other	1008.2	1238.4	1613.3
Current Assets	1068.9	1285.1	1683.1
Accts Payable	355.3	395.4	815.1
Debt Due	154.4	351.3	761.3
Other	410.0	460.4	441.5
Current Liab.	919.7	1207.1	2017.9
Fix. Chg. Cov.	405%	450%	430%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	9.5%	14.5%	*4.0%*
"Cash Flow"	3.5%	5.5%	*2.5%*
Earnings	2.5%	5.0%	*4.0%*
Dividends	2.5%	1.5%	*1.5%*
Book Value	6.5%	7.5%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	2283.8	2033.8	863.2	971.6	6152.4
2007	1602.6	2075.6	1218.2	1002.0	5898.4
2008	1657.5	2484.0	1639.1	1440.7	7221.3
2009	1716.3	*2585*	*1750*	*1548.7*	*7600*
2010	*1830*	*2900*	*1710*	*1460*	*7900*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.88	1.10	d.22	.25	2.00
2007	.97	1.20	d.15	d.05	1.94
2008	.82	1.24	d.07	.02	2.00
2009	.83	*1.33*	*d.05*	*d.01*	*2.10*
2010	*.90*	*1.35*	*d.06*	*d.04*	*2.15*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.31	.31	.31	.315	1.25
2006	.315	.315	.315	.32	1.27
2007	.32	.32	.32	.325	1.29
2008	.325	.325	.325	.33	1.31
2009	.33				

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to 3.2 million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2008 gas volumes: 293 MMcf. Breakdown: 56%, residential; 32%, commercial; 7%, industrial; and 5% other. 2008 depreciation rate 3.5%. Has around 4,560 employees. Officers and directors own approximately 1.9% of common stock (12/08 Proxy). Chairman and Chief Executive Officer: Robert W. Best. Incorporated: Texas. Address: P.O. Box 650205, Dallas, Texas 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy's core natural gas utility has performed nicely thus far in fiscal 2009 (which ends on September 30th). That can be attributed partially to an increase in rates, primarily for the Mid-Tex and Louisiana divisions. What's more, there has been a steady rise in throughput. And it's worth noting that bad debt expense as a percentage of revenues has been lower, reflecting more aggressive collection efforts.

Results for the other operations have been a mixed bag. The pipeline and storage segment is enjoying expanded transportation margins earned under asset optimization agreements. But the performance of the regulated transmission and storage segment is being weighed down by a rise in employee and pipeline maintenance costs. Also, the nonregulated marketing segment is encountering a reduction in unrealized margins, reflecting less volatility in natural gas prices.

All things considered, earnings per share stand to rise around 5%, to $2.10, this fiscal year. Assuming further expansion in operating margins, the bottom line may advance to $2.15 a share in fiscal 2010.

We envision steady, though unexciting, profit growth over the 2012-2014 period. The utility is one of the country's leading natural gas-only distributors, now serving customers across 12 states. Moreover, the unregulated segments, especially pipelines, possess healthy overall prospects. Lastly, management may get back to its successful strategy of purchasing less-efficient utilities and shoring up their profitability via expense-reduction efforts, rate relief, and aggressive marketing. In the present configuration, annual share-net gains may be in the mid-single-digit range over the 3- to 5-year time frame.

The good-quality stock offers an appealing dividend yield. Further moderate hikes in the payout seem plausible, as well. Earnings coverage ought to remain adequate. The shares are timely.

For a natural gas utility stock, total return possibilities appear decent. Meter growth has slowed, but the company is benefiting from a high level of gas flowing through its Texas pipelines from the Barnett Shale.

Frederick L. Harris, III *March 13, 2009*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '99, d23¢; '00, 12¢; '03, d17¢; '06, d18¢; '07, d2¢. Next egs. rpt. due early May. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	80

LACLEDE GROUP NYSE-LG

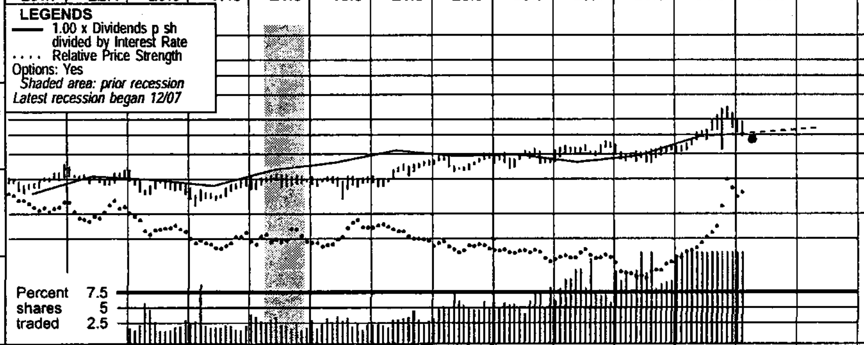
RECENT PRICE 38.10 | P/E RATIO 13.4 (Trailing: 12.4, Median: 15.0) | RELATIVE P/E RATIO 1.30 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 2 Raised 10/10/08
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Lowered 2/13/09
BETA .65 (1.00 = Market)

High:	27.9	27.0	24.8	25.5	25.0	30.0	32.5	34.3	37.5	36.0	55.8	48.3		
Low:	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9	29.1	28.8	31.9	38.0		

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+55%)	15%
Low	45	(+20%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	9	0	0	2	0	0	6	0
to Sell	0	9	0	0	2	0	0	6	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	72	97	82
to Sell	55	50	72
Hld's(000)	10492	11750	11943

Percent shares traded 7.5 / 5 / 2.5

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	20.3	-44.9
3 yr.	33.3	-44.1
5 yr.	58.9	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
32.33	33.43	24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	**102.65**	**96.10**	Revenues per sh	**111.55**
2.81	2.65	2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	**4.65**	**4.50**	"Cash Flow" per sh	**5.40**
1.61	1.42	1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	**2.85**	**2.60**	Earnings per sh A B	**3.00**
1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	**1.53**	**1.57**	Div'ds Decl'd per sh C■	**1.70**
2.62	2.50	2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	**2.65**	**2.70**	Cap'l Spending per sh	**3.45**
12.19	12.44	13.05	13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	**23.60**	**25.10**	Book Value per sh D	**28.05**
15.59	15.67	17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	**22.50**	**23.00**	Common Shs Outst'g E	**26.00**
13.5	16.4	15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	*Bold figures are*		Avg Ann'l P/E Ratio	**17.5**
.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	.89	*Value Line*		Relative P/E Ratio	**1.15**
5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	*estimates*		Avg Ann'l Div'd Yield	**3.2%**

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
491.6	566.1	1002.1	755.2	1050.3	1250.3	1597.0	1997.6	2021.6	2209.0	**2310**	**2210**	Revenues ($mill) A	**2900**
26.9	26.0	30.5	22.4	34.6	36.1	40.1	50.5	49.8	57.6	**65.0**	**60.0**	Net Profit ($mill)	**80.0**
35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	31.3%	**31.5%**	**31.5%**	Income Tax Rate	**35.0%**
5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	2.6%	**2.8%**	**2.7%**	Net Profit Margin	**2.8%**
41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	48.1%	49.5%	45.3%	44.4%	**45.0%**	**45.0%**	Long-Term Debt Ratio	**47.0%**
57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	55.5%	**55.0%**	**55.0%**	Common Equity Ratio	**53.0%**
488.6	519.2	574.1	546.6	605.0	737.4	707.9	798.9	784.5	876.1	**965**	**1050**	Total Capital ($mill)	**1375**
519.4	575.4	602.5	594.4	621.2	646.9	679.5	763.8	793.8	823.2	**855**	**880**	Net Plant ($mill)	**980**
7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	8.1%	**8.0%**	**7.0%**	Return on Total Cap'l	**7.0%**
9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	11.8%	**12.5%**	**10.5%**	Return on Shr. Equity	**11.0%**
9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	**12.5%**	**10.5%**	Return on Com Equity	**11.0%**
1.0%	.2%	1.8%	NMF	3.1%	2.7%	3.1%	5.1%	4.3%	5.2%	**6.0%**	**4.0%**	Retained to Com Eq	**5.0%**
89%	98%	83%	113%	74%	73%	72%	59%	63%	56%	**53%**	**60%**	All Div'ds to Net Prof	**55%**

CAPITAL STRUCTURE as of 12/31/08
Total Debt $652.9 mill. **Due in 5 Yrs** $50.0 mill.
LT Debt $389.2 mill. **LT Interest** $25.0 mill.
(Total interest coverage: 3.0x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/08 $248.3 mill. **Oblig.** $308.7 mill.
Pfd Stock $.5 mill. **Pfd Div'd** $.03 mill.
Common Stock 22,135,185 shs.
as of 1/29/09

MARKET CAP: $850 million (Small Cap)

CURRENT POSITION ($MILL.)	2007	2008	12/31/08
Cash Assets	52.7	14.9	30.1
Other	414.6	547.0	609.8
Current Assets	467.3	561.9	639.9
Accts Payable	106.8	159.6	175.3
Debt Due	251.6	216.1	263.7
Other	115.3	103.5	121.7
Current Liab.	473.7	479.2	560.7
Fix. Chg. Cov.	282%	377%	330%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	11.5%	14.0%	2.5%
"Cash Flow"	2.0%	6.5%	5.5%
Earnings	3.5%	9.5%	3.5%
Dividends	1.0%	1.5%	2.5%
Book Value	3.5%	5.5%	5.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	689.2	708.8	330.6	269.0	1997.6
2007	539.6	700.8	457.9	323.3	2021.6
2008	504.0	747.7	505.5	451.8	2209.0
2009	674.3	**700**	**485**	**450.7**	**2310**
2010	**555**	**555**	**550**	**550**	**2210**

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	1.23	1.05	.13	d.04	2.37
2007	.89	.97	.43	.03	2.31
2008	.99	1.39	.41	d.14	2.64
2009	1.42	**1.25**	**.30**	**d.12**	**2.85**
2010	**1.03**	**1.21**	**.38**	**d.02**	**2.60**

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.34	.345	.345	.345	1.38
2006	.345	.355	.355	.355	1.41
2007	.365	.365	.365	.365	1.46
2008	.375	.375	.375	.375	1.50
2009	.385				

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 10 other counties. Has roughly 630,000 customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Therms sold and transported in fiscal 2008: 1.08 mill. Revenue mix for regulated operations: residential, 62%; commercial and industrial, 24%; transportation, 1%; other, 13%. Has around 1,807 employees. Officers and directors own approximately 7.2% of common shares (1/09 proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Laclede Group started fiscal 2009 (which ends on September 30th) in excellent fashion. That was made possible primarily by Laclede Energy Resources, which benefited, in part, from higher volumes (attributable to contracting for additional pipeline capacity). That division also enjoyed wider margins on sales of natural gas, due to depressed supply pricing in the Midwest from increased shale supply production. Meanwhile, profits for Laclede Gas were moderately higher than the year-earlier figure, arising from greater income from natural gas sales, brought about by colder weather and higher Infrastructure System Replacement Surcharge revenues. But a rise in both operating expenses and investment losses largely offset these results.

At this juncture, the bottom line stands to advance about 8%, to $2.85 a share, in fiscal 2009. Earnings may be lower next year, however, because of the tough comparison.

Unexciting results appear to be in store for the energy firm over the 2012-2014 period. Growth in the customer base for the natural gas distribution unit will probably remain moderate. (In fact, the number of customers in fiscal 2008 was just 2% higher than in fiscal 1998.) That's because the service territory, located in eastern Missouri, is in a mature phase. We think the non-regulated division has promising expansion opportunities, but it has contributed only a small portion to Laclede Group's profits on a historical basis. A major acquisition could help to offset this, but it seems that no such plans are on the agenda at this time. Consequently, annual earnings-per-share growth could be just between 4% and 5% over the 3- to 5-year horizon.

This stock, ranked favorably for both Timeliness and Safety, offers a modestly appealing current yield. Additional hikes in the dividend will likely be gradual, though. That is largely because of the regulated gas operation's unspectacular long-term prospects.

The shares of Laclede have limited long-term total-return potential, given the current quotation and our assumption of moderate future increases in the distribution.

Frederick L. Harris, III *March 13, 2009*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late April. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '08: $340.4 mill., $15.48/sh.
(E) In millions.
(F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	75

NEW JERSEY RES. NYSE-NJR

RECENT PRICE	32.25	P/E RATIO	12.9 (Trailing: 11.7 Median: 15.0)	RELATIVE P/E RATIO	1.25	DIV'D YLD	3.8%	VALUE LINE

TIMELINESS **2** Raised 11/28/08

SAFETY **1** Raised 9/15/06

TECHNICAL **2** Raised 11/21/08

BETA .65 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	17.9	18.3	19.8	21.7	22.4	26.4	29.7	32.9	35.4	37.6	41.1	42.4
Low:	14.0	14.9	16.1	16.6	16.2	20.0	24.3	27.1	27.7	30.3	24.6	32.2

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

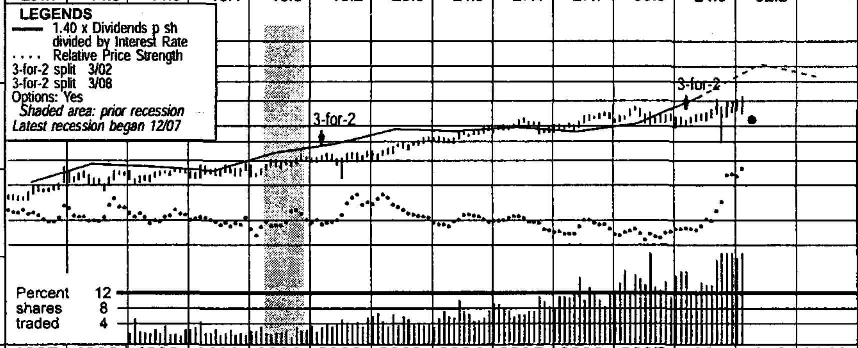
	Price	Gain	Ann'l Total Return
High	45	(+40%)	12%
Low	35	(+10%)	6%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	1	2	0	0	1	0	1	2	3
to Sell	0	2	0	0	1	0	0	1	4

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	85	90	64
to Sell	70	62	88
Hld's(000)	26518	26910	26312



% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	18.3	-44.9
3 yr.	28.7	-44.1
5 yr.	58.7	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
12.02	12.81	11.36	13.48	17.31	17.73	22.65	29.42	51.22	44.11	62.29	60.89	76.19	79.63	72.62	90.74	*89.20*	*90.95*	Revenues per sh A	*95.00*
1.42	1.54	1.42	1.48	1.63	1.74	1.86	1.99	2.12	2.14	2.38	2.50	2.62	2.73	2.44	3.62	*3.40*	*3.60*	"Cash Flow" per sh	*3.75*
.76	.84	.86	.92	.99	1.04	1.11	1.20	1.30	1.39	1.59	1.70	1.77	1.87	1.55	2.70	*2.50*	*2.70*	Earnings per sh B	*2.85*
.68	.68	.68	.69	.71	.73	.75	.76	.78	.80	.83	.87	.91	.96	1.01	1.11	*1.24*	*1.28*	Div'ds Decl'd per sh C■	*1.40*
1.54	1.40	1.18	1.19	1.15	1.07	1.21	1.23	1.10	1.02	1.14	1.45	1.28	1.28	1.46	1.72	*1.75*	*1.75*	Cap'l Spending per sh	*1.80*
6.54	6.43	6.47	6.73	6.92	7.26	7.57	8.29	8.80	8.71	10.26	11.25	10.60	15.00	15.50	17.28	*18.80*	*20.75*	Book Value per sh D	*25.75*
37.84	38.93	40.03	40.69	40.23	40.07	39.92	39.59	40.00	41.50	40.85	41.61	41.32	41.44	41.61	42.06	*42.50*	*43.00*	Common Shs Outst'g E	*45.00*
15.1	13.0	11.8	13.6	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*14.0*
.89	.85	.79	.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.87	1.15	.77	*estimates*		Relative P/E Ratio	*.95*
5.8%	6.2%	6.7%	5.6%	5.3%	4.6%	4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%			Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $757.1 mill. **Due in 5 Yrs** $175.6 mill.
LT Debt $460.7 mill. **LT Interest** $16.9 mill.
Incl. $8.8 mill. capitalized leases.
(LT interest earned: 4.8x; total interest coverage: 4.8x)
Pension Assets-9/08 $80.6 mill. **Oblig.** $102.4 mill.
Pfd Stock None

Common Stock 42,318,558 shs. as of 2/4/09
MARKET CAP: $1.4 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
904.3	1164.5	2048.4	1830.8	2544.4	2533.6	3148.3	3299.6	3021.8	3816.2	*3790*	*3910*	Revenues ($mill) A	*4275*
44.9	47.9	52.3	56.8	65.4	71.6	74.4	78.5	65.3	113.9	*105*	*115*	Net Profit ($mill)	*130*
36.2%	37.8%	38.0%	38.7%	39.4%	39.1%	39.1%	38.9%	38.8%	37.8%	*39.0%*	*39.0%*	Income Tax Rate	*40.0%*
5.0%	4.1%	2.6%	3.1%	2.6%	2.8%	2.4%	2.4%	2.2%	3.0%	*2.8%*	*3.0%*	Net Profit Margin	*3.0%*
48.7%	47.0%	50.1%	50.6%	38.1%	40.3%	42.0%	34.8%	37.3%	38.5%	*38.5%*	*37.0%*	Long-Term Debt Ratio	*33.0%*
51.2%	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	62.7%	61.5%	*61.5%*	*63.0%*	Common Equity Ratio	*67.0%*
590.4	620.1	706.2	732.4	676.8	783.8	755.3	954.0	1028.0	1182.1	*1300*	*1415*	Total Capital ($mill)	*1730*
705.4	730.6	743.9	756.4	852.6	880.4	905.1	934.9	970.9	1017.3	*1040*	*1060*	Net Plant ($mill)	*1125*
9.0%	9.0%	8.5%	8.7%	10.7%	10.1%	11.2%	9.6%	7.7%	10.7%	*9.0%*	*9.0%*	Return on Total Cap'l	*8.0%*
14.8%	14.6%	14.8%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	*13.5%*	*13.0%*	Return on Shr. Equity	*11.0%*
14.8%	14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	*13.5%*	*13.0%*	Return on Com Equity	*11.0%*
5.0%	5.4%	6.1%	6.9%	7.7%	7.8%	8.5%	6.3%	3.6%	9.5%	*6.5%*	*7.0%*	Retained to Com Eq	*5.5%*
67%	63%	59%	56%	51%	49%	50%	50%	64%	40%	*50%*	*47%*	All Div'ds to Net Prof	*49%*

CURRENT POSITION ($MILL.)	2007	2008	12/31/08
Cash Assets	5.1	42.6	26.0
Other	794.8	1067.1	1046.5
Current Assets	799.9	1109.7	1072.5
Accts Payable	64.4	61.7	43.4
Debt Due	260.8	238.3	296.4
Other	378.1	594.0	578.7
Current Liab.	703.3	894.0	918.5
Fix. Chg. Cov.	461%	450%	450%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	17.5%	9.0%	*2.5%*
"Cash Flow"	6.0%	6.0%	*4.0%*
Earnings	7.5%	7.5%	*5.5%*
Dividends	4.0%	5.0%	*5.5%*
Book Value	8.5%	11.5%	*8.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	1164	1064	536.1	535.5	3299.6
2007	737.4	1029	662.2	593.2	3021.8
2008	811.1	1178	1000	827.1	3816.2
2009	801.3	*1175*	*993.7*	*820*	*3790*
2010	*830*	*1205*	*1025*	*850*	*3910*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.82	1.43	d.09	d.29	1.87
2007	.70	.19	.60	.06	1.55 F
2008	.87	.30	d.18	1.86	2.70
2009	.77	*.33*	*d.10*	*1.50*	*2.50*
2010	*.80*	*.40*	*d.05*	*1.55*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C E■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.227	.227	.227	.227	.91
2006	.24	.24	.24	.24	.96
2007	.253	.253	.253	.253	1.01
2008	.267	.28	.28	.28	1.11
2009	.31				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 484,000 customers at 9/30/08 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2008 volume: 99.6 bill. cu. ft. (59% firm, 6% interruptible industrial and electric utility, 35% off-system and capacity release). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2008 dep. rate: 2.9%. Has 854 empls. Off./dir. own about 1.7% of common (12/08Proxy). Chrmn., CEO, & Pres. : Laurence M. Downes. Inc.: N.J. Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

New Jersey Resources did not perform as well as expected during its 2009 fiscal first quarter (ended December 31st). The New Jersey Natural Gas (NJNG) unit did benefit from a recent rate case increase, and steady customer growth. That division added roughly 1,765 new customers over the December interim. However, that was not sufficient enough to offset the downturn at the company's NJR Energy Services (NJRES) unit. Narrower winter storage spreads, and a slowdown in contracted transportation capacity across the Northeast, cut this segment's contribution to earnings in half. Consequently, NJR's bottom line suffered.

Thus, we have trimmed this year's earnings figure approximately 11%. The domestic recession has prompted many consumers in NJR's service areas to scale back spending. Meanwhile, home foreclosure resulting in vacant domiciles adds another element of risk and uncertainty. In all, 2009's prospects have been hindered. But, on a brighter note,

Economic stimulus programs may bear fruit down the road. NJNG recently filed a proposal with the New Jersey Board of Public Utilities for two programs aimed at stimulating the local economy through energy efficiency, job creation, and infrastructure spending. If approved, these capital projects would create up to 100 jobs. The benefit to NJR would be an increase in the safety and reliability of its distribution system.

Meantime, we have introduced a 2010 bottom-line estimate of $2.70 a share. Top-line volumes ought to rebound next year due to the addition of utility customers, coupled with NJRES' capital projects. The Steckman Ridge storage facility and the recently completed 16-inch main pipeline both ought to contribute nicely.

These timely shares may appeal to momentum- and income-oriented accounts (Timeliness: 2). And the recent dividend hike of 10.7% only sweetens the deal; dividend growth is a hallmark here. Finally, New Jersey Resources' ability to hold up in such a difficult market is a plus. This characteristic is supported by the stock's top Safety rank (1), and high marks for Financial Strength and Price Stability.

Bryan Fong *March 13, 2009*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late April.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2008: $340.7 million, $8.09/share.
(E) In millions, adjusted for split.
(F) Restated.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	50

NICOR, INC. NYSE-GAS

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
29.17	11.4 (Trailing: 11.1) (Median: 15.0)	1.11	6.4%	VALUE LINE

TIMELINESS 3 Raised 12/7/07

SAFETY 3 Lowered 6/17/05

TECHNICAL 3 Lowered 2/20/09

BETA .75 (1.00 = Market)

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+125%)	26%
Low	40	(+35%)	13%

Insider Decisions

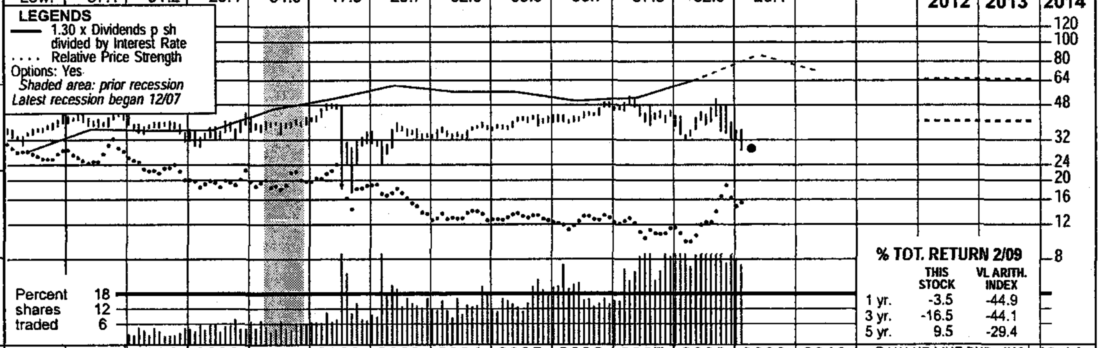
	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	0	0	0	0	0	1	0	0	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	91	119	105
to Sell	120	90	125
Hld's(000)	31875	32273	32539

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	44.4	42.9	43.9	42.4	49.0	39.3	39.7	43.0	49.9	53.7	52.0	36.3
Low:	37.1	31.2	29.4	34.0	17.3	23.7	32.0	35.5	38.7	37.8	32.3	28.4

Target Price Range
2012 | 2013 | 2014



% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-3.5	-44.9
3 yr.	-16.5	-44.1
5 yr.	9.5	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
31.02	31.23	29.42	37.39	41.33	30.84	34.45	50.52	57.30	43.11	60.46	62.12	76.00	65.92	69.20	83.68	**78.90**	**82.20**	Revenues per sh	**98.35**
3.80	4.11	4.19	4.97	5.29	5.21	5.59	6.16	6.41	6.03	5.37	6.00	6.19	6.82	6.96	6.85	**6.50**	**7.00**	"Cash Flow" per sh	**7.95**
1.97	2.07	1.96	2.42	2.55	2.31	2.57	2.94	3.01	2.88	2.11	2.22	2.27	2.87	2.99	2.63	**2.50**	**2.90**	Earnings per sh A	**3.30**
1.22	1.25	1.28	1.32	1.40	1.48	1.54	1.66	1.76	1.84	1.86	1.86	1.86	1.86	1.86	1.86	**1.86**	**1.86**	Div'ds Decl'd per sh B■	**1.86**
2.62	3.34	3.12	2.42	2.34	2.87	3.28	3.48	4.18	4.37	4.12	4.32	4.57	4.17	3.77	5.54	**4.35**	**4.50**	Cap'l Spending per sh	**4.85**
13.05	13.26	13.67	14.74	15.43	15.97	16.80	15.56	16.39	16.55	17.13	16.99	18.36	19.43	20.58	21.55	**22.25**	**23.30**	Book Value per sh	**27.05**
53.96	51.54	50.30	49.49	48.22	47.51	46.89	45.49	44.40	44.01	44.04	44.10	44.18	44.90	45.90	45.13	**45.00**	**45.00**	Common Shs Outst'g C	**45.00**
14.1	12.5	13.1	12.5	14.2	17.6	14.6	11.9	12.8	13.1	15.8	15.9	17.3	15.0	15.0	15.1	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
.83	.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.84	.92	.81	.80	.93	*Value Line*		Relative P/E Ratio	**1.05**
4.4%	4.8%	5.0%	4.4%	3.9%	3.6%	4.1%	4.7%	4.6%	4.9%	5.6%	5.3%	4.7%	4.3%	4.2%	4.7%	*estimates*		Avg Ann'l Div'd Yield	**3.5%**
						1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	3357.8	2960.0	3176.3	3776.6	**3550**	**3700**	Revenues ($mill)	**4200**
						121.9	136.4	136.3	128.0	93.1	98.1	101.1	128.3	135.2	119.5	**112.5**	**130**	Net Profit ($mill)	**150**
						34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	28.3%	26.3%	26.6%	27.0%	**27.0%**	**27.0%**	Income Tax Rate	**27.0%**
						7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.0%	4.3%	4.3%	3.2%	**3.2%**	**3.5%**	Net Profit Margin	**3.6%**
						35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	37.4%	36.3%	30.9%	31.5%	**31%**	**30%**	Long-Term Debt Ratio	**26%**
						64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	63.7%	69.0%	68.4%	**69%**	**70%**	Common Equity Ratio	**74%**
						1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1297.7	1370.7	1368.0	1421.1	**1450**	**1500**	Total Capital ($mill)	**1650**
						1735.2	1729.6	1768.6	1796.8	2484.2	2549.8	2659.1	2714.1	2757.3	2858.6	**2950**	**3060**	Net Plant ($mill)	**3380**
						10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.4%	10.9%	11.2%	9.7%	**9.0%**	**10.0%**	Return on Total Cap'l	**10.0%**
						15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	14.7%	14.3%	12.3%	**11.0%**	**12.5%**	Return on Shr. Equity	**12.0%**
						15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	14.7%	14.3%	12.3%	**11.0%**	**12.5%**	Return on Com Equity	**12.0%**
						6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	2.3%	5.2%	5.4%	3.6%	**3.0%**	**4.5%**	Retained to Com Eq	**5.5%**
						60%	56%	58%	63%	88%	84%	81%	65%	62%	71%	**74%**	**64%**	All Div'ds to Net Prof	**56%**

CAPITAL STRUCTURE as of 12/31/08
Total Debt $1237.9 mill. Due in 5 Yrs $914.9 mill.
LT Debt $448.0 mill. LT Interest $5.0 mill.
(Total interest coverage: 5.1x)

Pension Assets-12/08 $306.6 mill. **Oblig.** $270.2 mill.

Pfd Stock $.6 mill. Pfd Div'd None

Common Stock 45,198,311 shares
as of 2/17/09
MARKET CAP: $1.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	67.6	91.9	95.5
Other	843.1	931.9	1243.4
Current Assets	910.7	1023.8	1338.9
Accts Payable	564.5	428.2	411.3
Debt Due	350.0	444.0	789.9
Other	227.9	404.2	466.8
Current Liab.	1142.4	1276.4	1668.0
Fix. Chg. Cov.	543%	544%	461%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.0%	6.5%	*5.0%*
"Cash Flow"	3.0%	3.0%	*2.5%*
Earnings	1.5%	1.0%	*2.5%*
Dividends	3.0%	0.5%	*Nil*
Book Value	3.0%	4.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1319.4	451.3	351.1	838.2	2960.0
2007	1334.7	556.9	365.2	919.5	3176.3
2008	1595.7	699.8	440.3	1040.8	3776.6
2009	***1500***	***650***	***400***	***1000***	***3550***
2010	***1550***	***675***	***425***	***1050***	***3700***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.99	.19	.39	1.30	2.87
2007	1.04	.40	.32	1.22	2.98
2008	.91	.64	.03	1.05	2.63
2009	***.90***	***.35***	***.25***	***1.00***	***2.50***
2010	***1.00***	***.45***	***.35***	***1.10***	***2.90***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.465	.465	.465	.465	1.86
2006	.465	.465	.465	.465	1.86
2007	.465	.465	.465	.465	1.86
2008	.465	.465	.465	.465	1.86
2009	.465	.465			

BUSINESS: Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.2 million customers in northern and western Illinois. 2008 gas delivered: 498.1 Bcf, incl. 222.6 Bcf from transportation. 2008 gas sales (275.5 bcf): residential, 93%; commercial, 6%; industrial, 1%. Principal supplying pipelines: Natural Gas Pipeline, Horizon Pipeline, and TGPC. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested oil and gas E&P, 6/93. Has about 3,900 employees. Officers/directors own about 2.2% of common stock (3/08 proxy). Chairman and Chief Executive Officer: Russ Strobel. Incorporated: *Illinois*. Address: *1844 Ferry Road, Naperville, Illinois 60563*. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor struggled in the second half of 2008. Most recently, the company posted earnings of $1.05 a share in the fourth quarter, which beat our estimate but still fell short of the prior-year tally. Rising costs coupled with the weak economic environment weighed on GAS' performance. As a result, annual share net fell below 2007's mark of $2.98. Nicor continues to be pressured by higher operating costs.

The company awaits a decision for a rate case filed with the Illinois Commerce Commission (ICC). Given rising expenditures, the utility filed a case for an overall increase in rates. Nicor seeks to raise its rate base by $140.4 million to reflect a return of equity of 11.15%. The new rate would allow the company to better adjust to the current market conditions. In response, the ICC proposed a base increase of $68.8 million, which reflects a cost of equity of 10.17%. The proposal also includes two rate mechanisms focused on energy efficiency. Management is in the process of responding to this offer. After this, Nicor and the ICC will move toward a final decision, which should be announced this month. Accordingly, we recommend investors monitor this situation since it will likely have a heavy bearing on this equity's performance going forward.

We have lowered our estimates for 2009. We look for the bottom line to come in at about $2.50 a share, which is near the proposed base by the ICC. This estimate assumes normal weather and is supported by this utility's steady cash flow. However, if the rate case is approved, our estimates may prove to be conservative.

We are introducing our expectations for 2010. We look for the top and bottom lines to bounce back next year. The shipping business should begin to strengthen over this time frame. Accordingly, we estimate earnings of $2.90 a share.

This stock is ranked 3 (Average) for Timeliness. Nicor's prospects are somewhat ill-defined, given the pending rate case. Thus, we recommend most investors take a wait-and-see approach. However, income-oriented accounts should note that this issue offers an attractive dividend yield, which is above the average for a natural gas utility.

Richard Gallagher *March 13, 2009*

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢); '05, 80¢; '06, (17¢); '07 (13¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Next egs. report due early May.
(B) Dividends historically paid mid February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions.

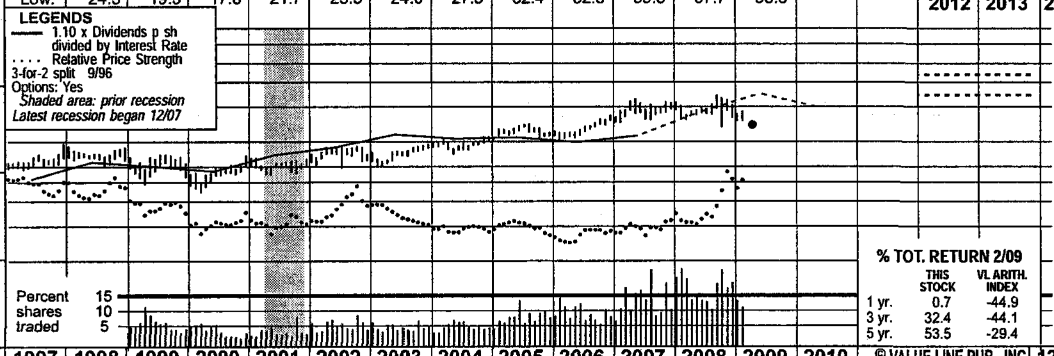
Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	75

N.W. NAT'L GAS NYSE-NWN

RECENT PRICE 38.95 | P/E RATIO 14.3 (Trailing: 15.1 / Median: 16.0) | RELATIVE P/E RATIO 1.39 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 2 Raised 2/20/09
SAFETY 1 Raised 3/18/05
TECHNICAL 2 Raised 3/6/09
BETA .60 (1.00 = Market)

High:	30.8	27.9	27.5	26.8	30.7	31.3	34.1	39.6	43.7	52.8	55.2	45.7
Low:	24.3	19.5	17.8	21.7	23.5	24.0	27.5	32.4	32.8	39.8	37.7	38.8



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+80%)	19%
Low	55	(+40%)	12%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	1	0	0	0	0	0	0
Options	0	0	1	0	1	2	0	1	0
to Sell	0	0	1	0	1	2	0	2	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	77	78	65
to Sell	92	71	74
Hld's(000)	16772	16947	16310

Percent shares traded 15 10 5

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	0.7	-44.9
3 yr.	32.4	-44.1
5 yr.	53.5	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
18.15	18.30	16.02	16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.17	*39.60*	*41.50*	Revenues per sh	*48.20*
3.74	3.50	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.29	*5.60*	*5.85*	"Cash Flow" per sh	*6.75*
1.74	1.63	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.58	*2.75*	*2.85*	Earnings per sh A	*3.45*
1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	*1.58*	*1.66*	Div'ds Decl'd per sh B■	*2.00*
3.61	4.23	3.02	3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	4.15	*4.50*	*4.50*	Cap'l Spending per sh	*4.50*
13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.70	*24.90*	*26.10*	Book Value per sh	*30.50*
19.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	*26.50*	*26.50*	Common Shs Outst'g C	*28.00*
12.9	13.0	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.14	*Value Line*		Relative P/E Ratio	*1.20*
5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.2%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $760.0 mill. **Due in 5 Yrs** $259.8 mill.
LT Debt $512.0 mill. **LT Interest** $37.0 mill.

(Total interest coverage: 4.0x)

Pension Assets-12/07 $241 mill.
Oblig. $260 mill.
Pfd Stock None

Common Stock 26.5 mill. shares

MARKET CAP $1.0 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
455.8	532.1	650.3	641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	*1050*	*1100*	Revenues ($mill)	*1350*
44.9	47.8	50.2	43.8	46.0	50.6	58.1	65.2	74.5	68.5	*73.0*	*75.5*	Net Profit ($mill)	*96.5*
35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	*7.0%*	*6.9%*	Net Profit Margin	*7.2%*
46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	*47%*	*47%*	Long-Term Debt Ratio	*47%*
49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	*53%*	*53%*	Common Equity Ratio	*53%*
861.5	887.8	880.5	937.3	1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	*1180*	*1225*	Total Capital ($mill)	*1400*
895.9	934.0	965.0	995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.0	*1600*	*1660*	Net Plant ($mill)	*1900*
6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	*8.0%*	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	11.2%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.0%*
9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	11.2%	*11.0%*	*11.0%*	Return on Com Equity	*11.0%*
2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.7%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
74%	70%	67%	79%	72%	69%	63%	59%	52%	59%	*57%*	*58%*	All Div'ds to Net Prof	*58%*

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	5.8	6.1	6.9
Other	303.0	268.8	474.1
Current Assets	308.8	274.9	481.0
Accts Payable	113.6	119.7	94.4
Debt Due	129.6	148.1	248.0
Other	98.3	122.1	208.9
Current Liab.	341.5	389.9	551.3
Fx. Chg. Cov.	349%	408%	393%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '12-'14
Revenues	8.5%	8.5%	6.5%
"Cash Flow"	3.0%	5.5%	5.0%
Earnings	3.0%	6.5%	7.0%
Dividends	1.5%	2.0%	5.5%
Book Value	3.5%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	390.4	171.0	114.9	336.9	1013.2
2007	394.1	183.2	124.2	331.7	1033.2
2008	387.7	191.3	109.7	349.2	1037.9
2009	*390*	*200*	*120*	*340*	*1050*
2010	*410*	*210*	*125*	*355*	*1100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.48	.07	d.35	1.15	2.35
2007	1.77	.10	d.22	1.11	2.76
2008	1.63	.08	d.38	1.25	2.58
2009	*1.72*	*.10*	*d.34*	*1.27*	*2.75*
2010	*1.75*	*.11*	*d.33*	*1.32*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.325	.325	.325	.345	1.32
2006	.345	.345	.345	.355	1.39
2007	.355	.355	.355	.375	1.44
2008	.375	.375	.375	.395	1.52
2009	.395				

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 662,000 customers, in Oregon (90% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 55%; commercial, 28%; industrial, gas transportation, and other, 17%. Employs 1,130. Barclays Global owns 6.5% of shares; officers and directors, 1.3% (4/08 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural's fourth-quarter earnings gain was a bit above normal. In the final period of 2008, the company profited from its gas cost-sharing arrangement in Oregon, where it had lost money in the prior-year period. Operating and maintenance costs declined 12%, year to year, and the Oregon weather normalization clause helped, as well, though it had no effect on 2007 December-period profits. Despite gas cost-sharing profit *in* the fourth quarter, Northwest lost about $0.11 a share from the arrangement in 2008. Customer growth, though, slowed to 1.6% in 2008, well below the recent average.

Earnings will likely rise nicely in 2009. Northwest guided to a range of $2.55 to $2.70 a share this year, but we think the company will do a bit better. Even though customer growth will probably be modest in 2009, Northwest should continue to garner new accounts from customers switching to gas from other sources of heat. The revised gas cost-sharing system in Oregon should also help, as the company should benefit from gas prices that are now well below last fall; Northwest's gas cost forecast is approved by the Oregon PUC in October. The new arrangement should reduce earnings swings, as Northwest will book only 10% or 20% of the profit or loss on the cost of gas, down from one-third through 2008.

Earnings from present operations will probably rise steadily through 2012-2014. Customer growth will likely continue to exceed the U.S. average of around 1% per year. Oregon's enlightened regulations should protect Northwest from the vagaries of the weather, and Washington will probably institute a weather adjustment clause, as well. Costs should rise at a slower pace than the customer roster. But

Two large projects could significantly boost Northwest's earnings by 2014. If regulators give all necessary approvals, a gas storage project in California and a new gas pipeline in Oregon will come on stream in 2011-2012. Together, they could require over $525 million of investment by Northwest. The company would have to sell some stock, but the projects could add at least $0.35 a share to our forecast.

These top-quality shares have solid risk-adjusted total-return potential.

Sigourney B. Romaine *March 13, 2009*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03). Next earnings report due early May.

(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.

(C) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	80

PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE 22.46 | P/E RATIO 14.0 (Trailing: 15.0 / Median: 18.0) | RELATIVE P/E RATIO 1.36 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 3 Raised 6/15/07
SAFETY 2 New 7/27/90
TECHNICAL 2 Lowered 1/9/09
BETA .65 (1.00 = Market)

High:	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0	
Low:	13.9	14.3	11.8	14.6	13.7	16.6	19.2	21.3	23.2	22.0	21.7	22.4	

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

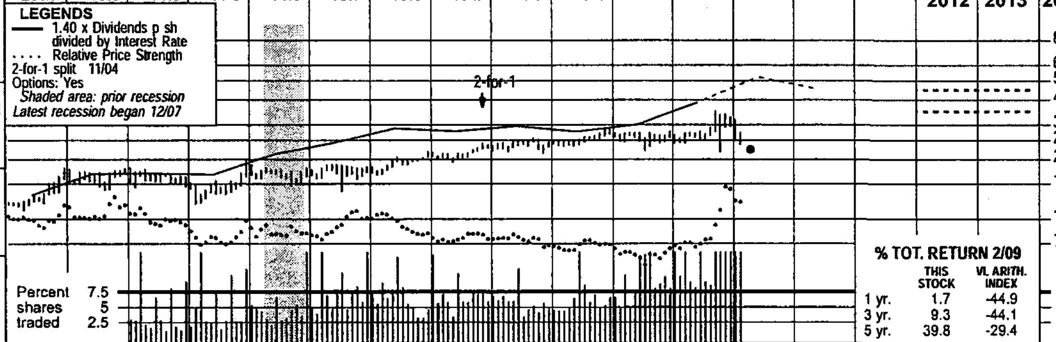
	Price	Gain	Ann'l Total Return
High	45	(+100%)	23%
Low	35	(+55%)	16%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	78	97	82
to Sell	85	77	96
Hld's(000)	36778	36688	35228



% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.7	-44.9
3 yr.	9.3	-44.1
5 yr.	39.8	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
10.57	10.82	8.76	11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	*29.25*	*30.15*	Revenues per sh A	*33.15*
1.14	1.13	1.25	1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	*2.85*	*3.05*	"Cash Flow" per sh	*3.40*
.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	*1.60*	*1.80*	Earnings per sh B	*2.15*
.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	*1.05*	*1.10*	Div'ds Decl'd per sh C■	*1.25*
1.58	1.95	1.72	1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	2.47	*3.15*	*2.10*	Cap'l Spending per sh	*2.25*
5.45	5.68	6.16	6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	*12.65*	*13.45*	Book Value per sh D	*15.85*
52.30	53.15	57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.26	*73.50*	*73.50*	Common Shs Outst'g E	*73.00*
15.4	15.7	13.8	13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	18.2	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*18.0*
.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.15	*estimates*		Relative P/E Ratio	*1.50*
4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%			Avg Ann'l Div'd Yield	*3.1%*

CAPITAL STRUCTURE as of 10/31/08
Total Debt $1230.8 mill. Due in 5 Yrs $150.0 mill.
LT Debt $794.3 mill. LT Interest $55.5 mill.
(LT interest earned: 4.0x; total interest coverage: 3.7x)

Pension Assets-10/08 $150.3 mill. Oblig. $143.5 mill.

Pfd Stock None

Common Stock 73,260,672 shs. as of 12/16/08

MARKET CAP: $1.7 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
686.5	830.4	1107.9	832.0	1220.8	1529.7	1761.1	1924.6	1711.3	2089.1	*2150*	*2215*	Revenues ($mill) A	*2420*
58.2	64.0	65.5	62.2	74.4	95.2	101.3	97.2	104.4	110.0	*120*	*135*	Net Profit ($mill)	*155*
39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.4%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	*5.5%*	*6.0%*	Net Profit Margin	*6.5%*
46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	*51.0%*	*49.5%*	Long-Term Debt Ratio	*47.0%*
53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	*49.0%*	*50.5%*	Common Equity Ratio	*53.0%*
914.7	978.4	1069.4	1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	*1900*	*1955*	Total Capital ($mill)	*2180*
1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	*2250*	*2300*	Net Plant ($mill)	*2450*
8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	*7.5%*	*8.5%*	Return on Total Cap'l	*8.5%*
11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	*12.5%*	*13.5%*	Return on Shr. Equity	*13.5%*
11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	*12.5%*	*13.5%*	Return on Com Equity	*13.5%*
3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	*4.0%*	*5.0%*	Retained to Com Eq	*6.0%*
72%	71%	75%	83%	74%	66%	68%	74%	70%	69%	*67%*	*62%*	All Div'ds to Net Prof	*57%*

CURRENT POSITION ($MILL.)	2006	2007	10/31/08
Cash Assets	8.9	7.5	7.0
Other	467.1	427.8	593.8
Current Assets	476.0	435.3	600.8
Accts Payable	80.3	143.6	132.3
Debt Due	170.0	195.0	436.5
Other	150.1	75.9	112.7
Current Liab.	400.4	424.5	681.5
Fix. Chg. Cov.	323%	309%	341%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.5%	10.0%	*4.0%*
"Cash Flow"	5.0%	7.0%	*4.5%*
Earnings	4.5%	6.5%	*7.5%*
Dividends	5.0%	4.5%	*3.5%*
Book Value	5.5%	6.0%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2006	921.4	483.2	237.9	282.2	1924.7
2007	677.2	531.5	224.4	278.2	1711.3
2008	788.5	634.2	354.7	311.7	2089.1
2009	*815*	*655*	*360*	*320*	*2150*
2010	*830*	*670*	*375*	*340*	*2215*

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2006	.94	.57	d.16	d.08	1.27
2007	.94	.69	d.12	d.11	1.40
2008	1.12	.66	d.10	d.18	1.49
2009	*1.13*	*.68*	*d.10*	*d.11*	*1.60*
2010	*1.15*	*.70*	*d.02*	*d.03*	*1.80*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.215	.23	.23	.23	.91
2006	.23	.24	.24	.24	.95
2007	.24	.25	.25	.25	.99
2008	.25	.26	.26	.26	1.03
2009	.26				

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 935,724 customers in North Carolina, South Carolina, and Tennessee. 2008 revenue mix: residential (39%), commercial (24%), industrial (12%), other (25%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 73.5% of revenues. '08 deprec. rate: 3.2%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,833 employees. Officers & directors own about 1.1% of common stock (1/09 proxy). Chairman, CEO, & President: Thomas E. Skains. Inc.: NC. Address: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas finished fiscal 2008 (ended October 31st) with solid results, despite the difficult economy. Revenues advanced 22% due to higher system throughput volumes, as well as additional customer accounts at the utility segment. However, the bottom-line increase was moderated owing to weaker contributions at the Southstar Energy Services unit. But progress was made.

The January-period bottom line came in slightly above the prior year. The top line benefited from additional customers in the residential, commercial, and conversion markets. Meanwhile, the Hardy Storage facility has begun to gain traction. It recently boosted its contribution to income by more than 20%. Margins were impacted last year because of declining natural gas prices, and a greater gas storage writedown than management expected. More recently, indications are that prices may start to help widen margins and boost earnings contributions from the nonutility portion of PNY's business mix.

Still, economic headwinds may weigh on this year's growth prospects. The past couple of quarters have experienced tapered growth in new accounts. And while these metrics are still relatively steady, the state of the regional economy suggests customer growth may slow further in the months to come. However, cost-cutting efforts ought to offset the slowdown and augur well for the bottom line, contributing to a share-net advance of roughly 7%.

We have introduced our 2010 earnings estimate at $1.80 a share. *The continued* utilization of Piedmont's Hardy Storage facility should provide a nice avenue for expansion next year. Meanwhile, it's only a matter of time before natural gas prices trend higher. And in the longer term, the Robeson liquefied natural gas storage project is slightly ahead of schedule and on budget to be in service by 2012.

These neutrally ranked shares may appeal to income-oriented accounts. Since our December review, they have declined approximately 21%. They still do not offer much in the way of capital appreciation potential. However, the recent downturn provides a more attractive entry point to this good-yielding stock.

Bryan Fong *March 13, 2009*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early May.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2008: $16.3 million, 22¢/share.
(E) In millions, adjusted for stock split.
(F) Quarters may not add to total due to change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	85

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 33.42 | P/E RATIO 13.8 (Trailing: 14.7 Median: 14.0) | RELATIVE P/E RATIO 1.34 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 2 Raised 12/26/08
SAFETY 2 Lowered 1/4/91
TECHNICAL 2 Raised 3/6/09
BETA .65 (1.00 = Market)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:			15.4	15.4	15.1	17.0	18.3	20.3	26.5	32.4	34.3	41.3	40.6	40.8			
Low:			11.0	10.8	12.3	13.8	14.1	15.3	19.7	24.9	25.6	31.2	25.2	32.8			

Target Price Range
2012 | 2013 | 2014

2012-14 PROJECTIONS

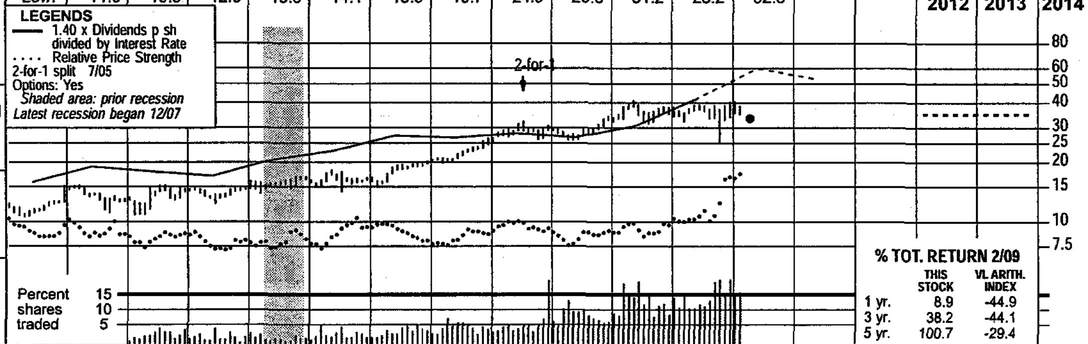
	Price	Gain	Ann'l Total Return
High	50	(+50%)	13%
Low	35	(+5%)	5%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	1	0	0	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	2	1	0	0	0	0	2	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	57	85	71
to Sell	71	58	59
Hld's(000)	17182	17430	17041



% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.9	-44.9
3 yr.	38.2	-44.1
5 yr.	100.7	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
17.03	17.45	16.50	16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	31.78	31.76	32.30	32.36	***32.80***	***33.55***	Revenues per sh	***36.35***
1.54	1.35	1.65	1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	3.51	3.20	3.27	***3.50***	***3.65***	"Cash Flow" per sh	***4.20***
.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.09	2.27	***2.45***	***2.65***	Earnings per sh A	***3.10***
.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.11	***1.20***	***1.28***	Div'ds Decl'd per sh B ■	***1.50***
1.87	1.93	2.08	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	3.21	2.51	1.88	2.08	***2.25***	***2.40***	Cap'l Spending per sh	***2.90***
7.17	7.23	7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.25	17.33	***18.35***	***19.35***	Book Value per sh C	***21.20***
19.61	21.43	21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	28.98	29.33	29.61	29.73	***30.50***	***31.00***	Common Shs Outst'g D	***33.00***
15.8	16.1	12.2	13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	***Bold figures are***		Avg Ann'l P/E Ratio	***14.0***
.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64	.91	.98	***Value Line***		Relative P/E Ratio	***.95***
5.9%	7.4%	7.2%	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	***estimates***		Avg Ann'l Div'd Yield	***3.5%***

CAPITAL STRUCTURE as of 12/31/08
Total Debt $570.4 mill. Due in 5 Yrs $302.7 mill.
LT Debt $332.8 mill. LT Interest $17.0 mill.
(Total interest coverage: 6.0x)

Pension Assets-12/08 $88.3 mill.
Oblig. $142.7 mill.

Pfd Stock none

Common Stock 29,738,256 common shs. as of 2/23/09

MARKET CAP: $1.0 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
392.5	515.9	837.3	505.1	696.8	819.1	921.0	931.4	956.4	962.0	***1000***	***1040***	Revenues ($mill)	***1200***
22.0	24.7	26.8	29.4	34.6	43.0	48.6	72.0	61.8	67.9	***75.0***	***80.0***	Net Profit ($mill)	***100.0***
42.8%	43.1%	42.2%	41.4%	40.6%	40.9%	41.5%	41.3%	41.9%	***43.3%***	***40.0%***	***40.0%***	Income Tax Rate	***40.0%***
5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	7.1%	***7.5%***	***7.7%***	Net Profit Margin	***8.3%***
53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	44.9%	44.7%	42.7%	39.2%	***40.5%***	***40.5%***	Long-Term Debt Ratio	***40.5%***
37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	60.8%	***59.5%***	***59.5%***	Common Equity Ratio	***59.5%***
405.9	443.5	516.2	512.5	608.4	675.0	710.3	801.1	839.0	848.0	***945***	***1010***	Total Capital ($mill)	***1175***
533.3	562.2	607.0	666.6	748.3	799.9	877.3	920.0	948.9	982.6	***1015***	***1040***	Net Plant ($mill)	***1220***
7.4%	7.4%	6.9%	7.6%	7.3%	7.9%	8.3%	10.1%	8.6%	***8.5%***	***9.0%***	***9.0%***	Return on Total Cap'l	***10.0%***
11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	12.4%	16.3%	12.8%	13.2%	***13.5%***	***13.5%***	Return on Shr. Equity	***14.5%***
14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.2%	***13.5%***	***13.5%***	Return on Com Equity	***14.5%***
4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	6.2%	10.2%	6.7%	6.8%	***7.0%***	***6.5%***	Retained to Com Eq	***7.0%***
72%	67%	76%	62%	57%	52%	50%	37%	48%	49%	***49%***	***50%***	All Div'ds to Net Prof	***50%***

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	7.9	11.7	5.8
Other	363.8	316.6	429.3
Current Assets	371.7	328.3	435.1
Accts Payable	101.6	101.2	120.2
Debt Due	197.0	118.4	237.6
Other	124.2	108.7	142.1
Current Liab.	422.8	328.3	499.9
Fix. Chg. Cov.	527%	476%	598%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.0%	4.0%	*2.0%*
"Cash Flow"	7.0%	9.0%	*4.0%*
Earnings	9.5%	12.5%	*5.5%*
Dividends	2.5%	4.5%	*7.0%*
Book Value	7.5%	12.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	372.6	153.8	154.7	250.3	931.4
2007	368.4	171.7	156.2	260.1	956.4
2008	348.1	135.8	210.4	267.7	962.0
2009	***365***	***160***	***200***	***275***	***1000***
2010	***375***	***170***	***210***	***285***	***1040***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.06	.20	.51	.69	2.46
2007	1.30	.21	d.05	.63	2.09
2008	1.32	.26	.04	.67	2.27
2009	***1.35***	***.30***	***.10***	***.70***	***2.45***
2010	***1.40***	***.35***	***.15***	***.75***	***2.65***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	--	.213	.213	.438	.86
2006	--	.225	.225	.470	.92
2007	--	.245	.245	.515	1.01
2008	--	.270	.270	.568	1.11
2009					

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 340,136 customers in New Jersey's southern counties, which covers about 2,500 square miles and includes Atlantic City. Gas revenue mix '08: residential, 46%; commercial, 23%; cogeneration and electric generation, 6%; industrial, 25%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 602 employees. Off./dir. control 1.0% of com. shares; Dimensional Fund Advisors, 6.5%; Barclays, 6.1% (3/08 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have held up well in recent months. The company reported a solid bottom-line advance for the fourth quarter and full-year 2008. Its nonutility operations posted healthy growth at the Asset Management & Marketing unit. The utility segment has also benefited from increased customer conversions to natural gas and higher margins on off-system sales. The customer base increased by roughly 1.3% in 2008, despite a considerable slowdown in the new housing construction market.

The company has attractive prospects for the coming years. Natural gas remains the fuel of choice in the markets served by South Jersey Gas, where the fuel enjoys a significant price advantage over alternatives. Moreover, healthy performance should continue at South Jersey's nonutility operations. Overall, share earnings will probably advance at a nice clip in 2009.

South Jersey Gas recently filed two petitions with the New Jersey Board of Public Utilities advancing economic stimulus plans. The first accelerates into 2009 and 2010 roughly $100 million of capital spending on various utility infrastructure projects. The company is seeking to recover, and earn a return on, this investment through higher rates. The second petition proposes a $17 million Energy Efficiency Tracker that encourages energy conservation while allowing SJG to earn a competitive return. In addition, South Jersey plans to file a base rate case in early 2010, which will reflect approximately $380 million in capital investment since the last filing.

The company leased out its interest in the Marcellus Shale. It has formed an agreement with an exploration and production company to develop the deep mineral rights on over 21,000 acres of the Marcellus Shale in western Pennsylvania. This move will allow South Jersey to realize the value of this asset without incurring the costs of drilling the acreage itself.

This stock is timely. Earnings and dividend growth should continue to 2012-2014. However, this appears to be partly reflected in the current quotation. The yield on this good-quality issue is also below the average of the gas-utility group.

Michael Napoli, CPA *March 13, 2009*

(A) Based on GAAP EPS through 2006, economic earnings thereafter. GAAP EPS: '07, $2.10; '08, $2.58. Excl. nonrecur. gain (loss): '01, $0.13; '08, ($0.70). Excl gain (losses) from discont. ops.: '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02); '07, $0.01. Earnings may not sum due to rounding. Next egs. report due late April/early May. (B) Div'ds paid early Apr., Jul., Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. regulatory assets. In 2008: $270.4 mill., $9.10 per shr. (D) In millions, adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	75

SOUTHWEST GAS NYSE-SWX

RECENT PRICE **18.15** | P/E RATIO **13.9** (Trailing: 12.9 / Median: 18.0) | RELATIVE P/E RATIO **1.35** | DIV'D YLD **5.2%** | VALUE LINE

TIMELINESS	3	Raised 5/23/08
SAFETY	3	Lowered 1/4/91
TECHNICAL	2	Raised 3/6/09

BETA .70 (1.00 = Market)

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+120%)	25%
Low	30	(+65%)	17%

Insider Decisions

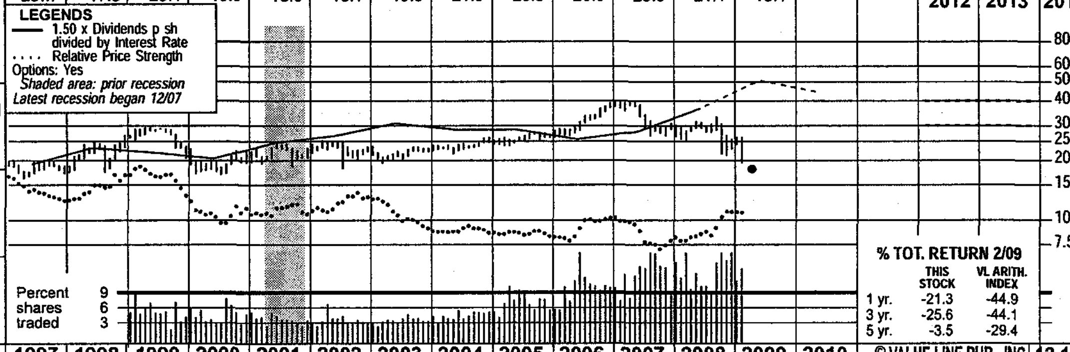
	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	2	1	1	0
Options	0	1	0	0	0	0	0	0	0
to Sell	0	3	0	0	0	2	0	0	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	80	85	69
to Sell	88	65	74
Hld's(000)	34496	34150	33669

High:	26.9	29.5	23.0	24.7	25.3	23.6	26.2	28.1	39.4	39.9	33.3	26.4
Low:	17.3	20.4	16.9	18.6	18.1	19.3	21.5	23.5	26.0	26.5	21.1	18.1

Target Price Range 2012 | 2013 | 2014



% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-21.3	-44.9
3 yr.	-25.6	-44.1
5 yr.	-3.5	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
25.68	28.16	23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	*44.45*	*46.75*	Revenues per sh	*55.00*
3.24	5.09	2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.75	*6.05*	*6.65*	"Cash Flow" per sh	*7.50*
.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	*1.50*	*1.85*	Earnings per sh A	*2.30*
.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	*.95*	*1.00*	Div'ds Decl'd per sh B■†	*1.15*
5.43	6.64	6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	*7.00*	*7.20*	Cap'l Spending per sh	*9.00*
15.96	16.38	14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.48	*24.45*	*25.00*	Book Value per sh	*26.00*
21.00	21.28	24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	*45.00*	*46.00*	Common Shs Outst'g C	*50.00*
26.5	14.0	NMF	NMF	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
1.57	.92	NMF	NMF	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.25	*Value Line*		Relative P/E Ratio	*1.00*
4.4%	4.7%	5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 12/31/08

Total Debt $1348.3 mill. **Due in 5 Yrs** $624.0 mill.
LT Debt $1285.5 mill. **LT Interest** $90.0 mill.
(Total interest coverage: 2.1x)
Leases, Uncapitalized Annual rentals $6.0 mill.
Pension Assets-12/08 $342.9 mill. **Oblig.** $558.9 mill.

Pfd Stock None

Common Stock 44,436,610 shs. as of 2/17/09

MARKET CAP: $800 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
936.9	1034.1	1396.7	1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	*2000*	*2150*	Revenues ($mill)	*2750*
39.3	38.3	37.2	38.6	38.5	58.9	48.1	80.5	83.2	61.0	*67.5*	*85.0*	Net Profit ($mill)	*115*
35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	*38.0%*	*38.0%*	Income Tax Rate	*36.0%*
4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	*3.4%*	*4.0%*	Net Profit Margin	*4.2%*
60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	*53.5%*	*52.5%*	Long-Term Debt Ratio	*51.0%*
35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	44.7%	*46.5%*	*47.5%*	Common Equity Ratio	*49.0%*
1424.7	1489.9	1417.6	1748.3	1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	*2375*	*2425*	Total Capital ($mill)	*2650*
1581.1	1686.1	1825.6	1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	*3100*	*3250*	Net Plant ($mill)	*3700*
4.8%	4.6%	5.1%	4.3%	4.2%	5.0%	4.3%	5.5%	5.5%	4.5%	*4.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	*6.0%*	*7.5%*	Return on Shr. Equity	*9.0%*
7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	*6.0%*	*7.5%*	Return on Com Equity	*9.0%*
2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	*2.5%*	*3.5%*	Retained to Com Eq	*4.5%*
64%	67%	71%	70%	72%	49%	65%	42%	44%	63%	*63%*	*54%*	All Div'ds to Net Prof	*50%*

CURRENT POSITION ($MILL.)	2006	2007	12/31/08
Cash Assets	18.8	32.0	26.4
Other	482.8	470.5	411.7
Current Assets	501.6	502.5	438.1
Accts Payable	265.7	220.7	191.4
Debt Due	27.5	47.1	62.8
Other	202.9	260.1	255.7
Current Liab.	496.1	527.9	509.9
Fix. Chg. Cov.	220%	229%	224%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	7.0%	4.5%	*2.0%*
"Cash Flow"	6.0%	4.0%	*4.0%*
Earnings	16.5%	8.0%	*4.5%*
Dividends	--	.5%	*5.0%*
Book Value	4.0%	4.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	676.9	430.9	351.8	565.1	2024.7
2007	793.7	426.6	371.5	560.3	2152.1
2008	813.6	447.3	374.4	509.4	2144.7
2009	*790*	*400*	*310*	*500*	*2000*
2010	*810*	*440*	*350*	*550*	*2150*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.11	.02	d.26	1.11	1.98
2007	1.17	d.01	d.22	1.01	1.95
2008	1.14	d.06	d.38	.71	1.39
2009	*1.00*	*d.05*	*d.35*	*.90*	*1.50*
2010	*1.05*	*Nil*	*d.30*	*1.10*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.205	.205	.205	.205	.82
2006	.205	.205	.205	.205	.82
2007	.205	.215	.215	.215	.85
2008	.215	.225	.225	.225	.89
2009	.225	.238			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.8 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2008 margin mix: residential and small commercial, 86%; large commercial and industrial, 5%; transportation, 9%. Total throughput: 2.4 billion therms. Sold PriMerit Bank, 7/96. Has 4,732 employees. Off. & Dir. own 1.8% of common stock; T. Rowe Price Associates, Inc., 6.7%; GAMCO Investors, Inc., 5.8% (3/08 Proxy). Chairman: James J. Kropid. Chief Executive Officer: Jeffrey W. Shaw. Inc.: California. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Shares of Southwest Gas have traded lower in the past six months. Share earnings for 2008 came in well below the prior-year tally. Customer growth dropped to its lowest level in over two decades, owing to the prolonged housing slowdown in the Southwest. This has also hurt performance at construction subsidiary NPL. Looking forward, the business environment will probably remain challenging in 2009. Thus, we anticipate unimpressive results for the current year, too. Operating performance may well improve in 2010, assuming success at controlling costs and an economic rebound.

The company has announced two rate case settlements. In Arizona, Southwest Gas was granted an annual rate increase of $33.5 million, which was somewhat less than the $50.2 million SWX had been seeking. Elsewhere, higher rates in California became effective in January. Looking ahead, Southwest is preparing to file a rate case in Nevada during the second quarter. The company's focus on obtaining rate relief and improving rate design is important, as it depends upon such improved revenue increases to help it cope with higher expenses.

Southwest Gas has announced a dividend increase. Starting in June, the quarterly dividend will be $0.2375 per share, almost 6% higher than the most recent payout. This follows similar increases in the past two years. This pattern is encouraging, and may well continue going forward.

Investors should be mindful of several caveats. Warmer-than-normal temperatures during the winter months can hinder profitability at Southwest Gas. Further efforts to expand operations would probably be accompanied by greater operating costs, too. Moreover, insufficient, or lagging, rate relief can hurt performance.

These shares are not a standout for the coming six to 12 months. Market conditions will likely continue to stymie growth at Southwest Gas in the near term. Looking further out, we anticipate higher earnings by 2012-2014. Moreover, this issue's healthy dividend yield may appeal to income-oriented investors. From the current quotation, this stock has good total return potential for a utility.

Michael Napoli, CPA *March 13, 2009*

(A) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Incl. asset writedown: '93, 44¢. Excl. loss from disc. ops.: '95, 75¢. Totals may not sum due to rounding. Next egs. report due early May. (B) Dividends historically paid early March, June, September, December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions.

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	70

WGL HOLDINGS NYSE-WGL

RECENT PRICE	28.99	P/E RATIO	11.6 (Trailing: 11.5 / Median: 15.0)	RELATIVE P/E RATIO	1.13	DIV'D YLD	5.0%	VALUE LINE

TIMELINESS **2** Raised 2/13/09
SAFETY **1** Raised 4/2/93
TECHNICAL **2** Raised 3/6/09
BETA .65 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	30.8	29.4	31.5	30.5	29.5	28.8	31.4	34.8	33.6	35.9	37.1 / 35.5
Low:	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8	27.0	29.8	22.4 / 28.9

2012-14 PROJECTIONS

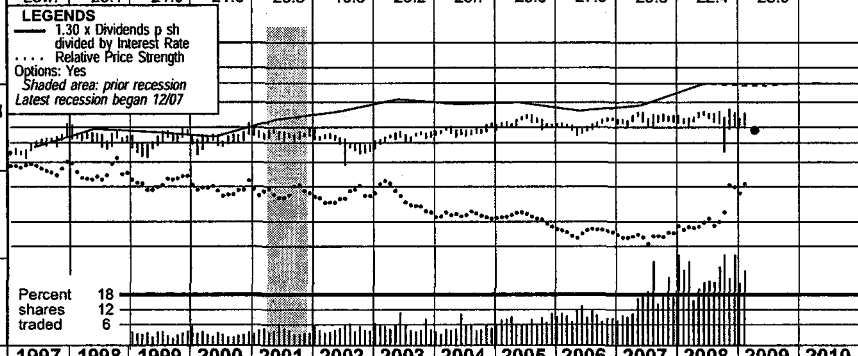
	Price	Gain	Ann'l Total Return
High	45	55%	15%
Low	35	20%	9%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	1	0	0	0	0	0	0	0
Options	0	5	1	0	0	2	0	4	0
to Sell	0	7	1	0	0	2	0	4	0

Institutional Decisions

	1Q2008	2Q2008	3Q2008
to Buy	106	95	83
to Sell	89	100	119
Hld's(000)	35559	34195	32939



Target Price Range

2012	2013	2014

% TOT. RETURN 2/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.8	-44.9
3 yr.	12.3	-44.1
5 yr.	30.2	-29.4

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
21.55	21.69	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	*53.50*	*54.60*	Revenues per sh A	*57.90*
2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.89	3.89	4.34	*4.40*	*4.45*	"Cash Flow" per sh	*4.70*
1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.10	2.44	*2.50*	*2.55*	Earnings per sh B	*2.75*
1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	*1.45*	*1.50*	Div'ds Decl'd per sh C■	*1.60*
2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	*3.00*	*3.00*	Cap'l Spending per sh	*2.50*
11.04	11.51	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	*22.05*	*23.10*	Book Value per sh D	*26.45*
41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	*50.00*	*50.00*	Common Shs Outst'g E	*50.00*
15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.82	.85	*Value*	*Line*	Relative P/E Ratio	*1.00*
5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 12/31/08
Total Debt $1073.0 mill. Due in 5 Yrs $264.5 mill.
LT Debt $657.7 mill. LT Interest $37.4 mill.
(LT interest earned: 5.9x; total interest coverage: 5.2x)
Pension Assets-9/08 $588.2 mill. Oblig. $590.5 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 50,124,429 shs. as of 1/31/09

MARKET CAP: $1.5 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
972.1	1031.1	1446.5	1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	*2675*	*2730*	Revenues ($mill) A	*2895*
68.8	84.6	89.9	55.7	112.3	98.0	104.8	96.0	102.9	122.9	*125*	*130*	Net Profit ($mill)	*140*
36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	*37.0%*	*37.0%*	Income Tax Rate	*38.0%*
7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	*4.7%*	*4.7%*	Net Profit Margin	*4.8%*
41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	*36.5%*	*35.5%*	Long-Term Debt Ratio	*34.0%*
56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	*62.0%*	*63.0%*	Common Equity Ratio	*64.5%*
1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	1526.1	1625.4	1679.5	*1780*	*1835*	Total Capital ($mill)	*2050*
1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	*2325*	*2420*	Net Plant ($mill)	*2720*
7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	*11.5%*	*11.0%*	Return on Shr. Equity	*10.5%*
9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	*12.0%*	*11.5%*	Return on Com Equity	*11.0%*
1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
82%	69%	67%	112%	56%	65%	62%	69%	66%	57%	*57%*	*57%*	All Div'ds to Net Prof	*58%*

CURRENT POSITION ($MILL.)	2007	2008	12/31/08
Cash Assets	4.9	6.2	8.8
Other	568.8	736.1	1066.3
Current Assets	573.7	742.3	1075.1
Accts Payable	216.9	243.1	326.9
Debt Due	205.4	347.0	415.3
Other	134.8	158.4	271.8
Current Liab.	557.1	748.5	1014.0
Fix. Chg. Cov.	432%	490%	500%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.5%	9.0%	*1.5%*
"Cash Flow"	3.5%	4.0%	*2.5%*
Earnings	2.0%	4.0%	*4.0%*
Dividends	1.5%	1.5%	*2.5%*
Book Value	4.0%	4.5%	*5.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	902.9	1064.5	346.9	323.6	2637.9
2007	732.9	1119.9	467.5	325.7	2646.0
2008	751.6	1020.0	464.7	391.9	2628.2
2009	821.5	*1024*	*469.5*	*360*	*2675*
2010	*835*	*1040*	*485*	*370*	*2730*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2006	.93	1.17	d.01	d.15	1.94
2007	.92	1.27	.22	d.31	2.10
2008	.96	1.66	.06	d.24	2.44
2009	1.03	*1.50*	*.15*	*d.18*	*2.50*
2010	*1.05*	*1.50*	*.15*	*d.15*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.325	.333	.333	.333	1.32
2006	.333	.338	.338	.338	1.34
2007	.34	.34	.34	.34	1.36
2008	.34	.36	.36	.36	1.42
2009	.36				

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,053,032 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. American Century Inv. own 7.1% of common stock; Off./dir. less than 1% (1/09 proxy). Chrmn. & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Addr.: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings started fiscal 2009 (began October 1st) on a high note. Its regulated utility business gained roughly 7,500 active metered accounts over the year-ago period. And the retail energy marketing segment's contribution to revenues and earnings got a boost from higher realized margins on the sale of natural gas. These items contributed nicely to the 9% top-line volume advance. Meanwhile, decreased labor and benefit costs, due to outsourcing, benefited margins. However, offsetting factors included a slowing of natural gas and electric volumes owing to a reduced number of customers at the retail energy segment. Still, in all, WGL's bottom line advanced 7.3% over this timeframe.

However, March-interim share net will likely fall short compared to the previous year. Over the past 12 months, WGL has initiated decoupling programs in both Virginia and the DC areas to help minimize the effects of weather and usage on its financial results. Thus, last year's second quarter benefited from increased consumption levels whereas 2008's has not. Moving forward, decoupling creates a smoothing effect on the bottom line, and ought to reduce earnings volatility.

On balance, though, the company ought to see its profits rise roughly 3% this year. The regulated utility segment ought to continue to benefit from additional active meters. However, many in this industry have been experiencing a moderation in new accounts. This stems from the sharp recessionary environment that has pushed up home foreclosures. Furthermore, natural gas consumption patterns may decline throughout all service areas as consumers try to cut monthly spending. Still, with over one million active meters, WGL appears to be in good shape to weather this economic storm.

These high-quality shares have provided a bit of a safe haven, as they have held up better than most stocks since our December review. They are also ranked to outperform the broader market in the coming year. What's more, dividend growth is a hallmark here. On the downside, WGL offers minimal appreciation potential for the coming 3 to 5 years, but this is typical for most utilities.

Bryan Fong *March 13, 2009*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes non-recurring losses: '01, (13¢); '02, (34¢); '07, (4¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late April. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '08: $291.3 million, $5.81/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	75

ATTACHMENT B

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AGL RESOURCES INC (NYSE)

Scottrade

AGL	28.46	-0.16	(-0.56%)	Vol. 229,976	16:02 ET

AGL Resources principal business is the distribution of natural gas to customers in central, northwest, northeast and southeast Georgia and the Chattanooga, Tennessee area through its natural gas distribution subsidiary. AGL's major service area is the ten county metropolitan Atlanta area.

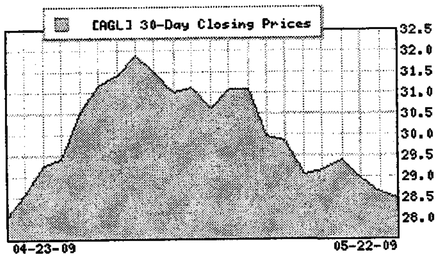
General Information

AGL RESOURCES
Ten Peachtree Place NE
Atlanta, GA 30309
Phone: 404 584-4000
Fax: 404 584-3945
Web: www.aglresources.com
Email: scave@aglresources.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	07/23/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	28.62
52 Week High	36.42
52 Week Low	24.02
Beta	0.43
20 Day Moving Average	453,827.84
Target Price Consensus	33.75



% Price Change

4 Week	1.50
12 Week	2.04
YTD	-9.22

% Price Change Relative to S&P 500

4 Week	-2.52
12 Week	-13.39
YTD	-5.30

Share Information

Shares Outstanding (millions)	77.09
Market Capitalization (millions)	2,193.90
Short Ratio	3.45
Last Split Date	12/04/1995

Dividend Information

Dividend Yield	6.04%
Annual Dividend	$1.72
Payout Ratio	0.55
Change in Payout Ratio	-0.02
Last Dividend Payout / Amount	05/13/2009 / $0.43

EPS Information

Current Quarter EPS Consensus Estimate	0.22
Current Year EPS Consensus Estimate	2.68
Estimated Long-Term EPS Growth Rate	5.30
Next EPS Report Date	07/23/2009

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.20
30 Days Ago	2.20
60 Days Ago	2.20
90 Days Ago	2.17

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	10.62	vs. Previous Year	33.62%	vs. Previous Year	-1.68%
Trailing 12 Months:	9.18	vs. Previous Quarter	59.79%	vs. Previous Quarter:	23.60%
PEG Ratio	1.99				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.24	03/31/09	13.92	03/31/09	3.66

Price/Cash Flow	6.08	12/31/08	12.23	12/31/08	3.20
Price / Sales	0.79	09/30/08	11.74	09/30/08	3.13
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.06	03/31/09	0.80	03/31/09	8.53
12/31/08	1.03	12/31/08	0.70	12/31/08	7.41
09/30/08	1.06	09/30/08	0.62	09/30/08	7.44
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	14.84	03/31/09	14.84	03/31/09	22.87
12/31/08	12.46	12/31/08	12.46	12/31/08	21.52
09/30/08	12.43	09/30/08	12.43	09/30/08	22.49
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	3.45	03/31/09	0.95	03/31/09	48.72
12/31/08	3.35	12/31/08	1.01	12/31/08	50.82
09/30/08	2.77	09/30/08	0.97	09/30/08	49.71

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ATMOS ENERGY CORP (NYSE)

Scottrade

ATO	23.91	-0.15	(-0.62%)	Vol. 290,909	16:03 ET

Atmos Energy Corporation distributes and sells natural gas to residential, commercial, industrial, agricultural and other customers. Atmos operates through five divisions in cities, towns and communities in service areas located in Colorado, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Missouri, South Carolina, Tennessee, Texas and Virginia. The Company has entered into an agreement to sell all of its natural gas utility operations in South Carolina. The Company also transports natural gas for others through its distribution system.

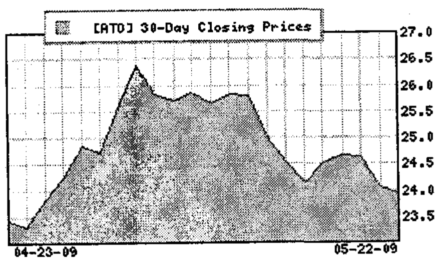
General Information

ATMOS ENERGY CP
Three Lincoln Centre 5430 Lbj Freeway
Suite 1800
Dallas, TX 75240
Phone: 972-934-9227
Fax: 972-855-3040
Web: www.atmosenergy.com
Email: InvestorRelations@atmosenergy.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	08/04/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	24.06
52 Week High	28.66
52 Week Low	19.68
Beta	0.52
20 Day Moving Average	664,797.38
Target Price Consensus	28.42



% Price Change

4 Week	2.05
12 Week	7.75
YTD	0.89

% Price Change Relative to S&P 500

4 Week	-1.99
12 Week	-8.55
YTD	4.16

Share Information

Shares Outstanding (millions)	91.91
Market Capitalization (millions)	2,197.66
Short Ratio	2.42
Last Split Date	05/17/1994

Dividend Information

Dividend Yield	5.52%
Annual Dividend	$1.32
Payout Ratio	0.63
Change in Payout Ratio	-0.03
Last Dividend Payout / Amount	02/23/2009 / $0.33

EPS Information

Current Quarter EPS Consensus Estimate	-0.10
Current Year EPS Consensus Estimate	2.08
Estimated Long-Term EPS Growth Rate	5.80
Next EPS Report Date	08/04/2009

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.57
30 Days Ago	2.57
60 Days Ago	2.57
90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.49	vs. Previous Year	7.26%	vs. Previous Year	-26.67%
Trailing 12 Months:	11.33	vs. Previous Quarter	60.24%	vs. Previous Quarter:	6.12%
PEG Ratio	1.97				

Price Ratios		**ROE**		**ROA**	
Price/Book	1.01	03/31/09	9.16	03/31/09	2.93
Price/Cash Flow	5.69	12/31/08	8.73	12/31/08	2.81
Price / Sales	0.33	09/30/08	8.67	09/30/08	2.82
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.15	03/31/09	0.90	03/31/09	2.91
12/31/08	0.83	12/31/08	0.55	12/31/08	2.51
09/30/08	1.06	09/30/08	0.59	09/30/08	2.50
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	4.61	03/31/09	4.61	03/31/09	23.70
12/31/08	4.05	12/31/08	4.05	12/31/08	22.70
09/30/08	4.05	09/30/08	4.05	09/30/08	22.65
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	11.66	03/31/09	1.00	03/31/09	49.89
12/31/08	12.20	12/31/08	0.83	12/31/08	45.28
09/30/08	11.99	09/30/08	1.03	09/30/08	50.81

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LACLEDE GROUP INC (NYSE)

Scottrade

LG	29.80	-0.35	(-1.16%)	Vol. 133,326	16:03 ET

The Laclede Group, Inc. is a public utility engaged in the retail distribution and transportation of natural gas. The Company, which is subject to the jurisdiction of the Missouri Public Service Commission, serves the City of St. Louis, St. Louis County, the City of St. Charles, St. Charles County, the town of Arnold, and parts of Franklin, Jefferson, St. Francois, Ste. Genevieve, Iron, Madison and Butler Counties, all in Missouri.

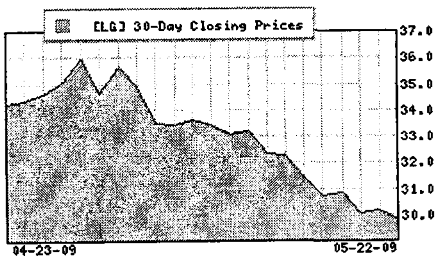
General Information

LACLEDE GRP INC
720 Olive Street
St. Louis, MO 63101
Phone: 314-342-0500
Fax: 314-421-1979
Web: www.thelacledegroup.com
Email: mkullman@lacledegas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	07/24/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	30.15
52 Week High	55.81
52 Week Low	29.75
Beta	0.09
20 Day Moving Average	208,767.66
Target Price Consensus	40



% Price Change		% Price Change Relative to S&P 500	
4 Week	-12.97	4 Week	-16.41
12 Week	-26.29	12 Week	-37.44
YTD	-36.38	YTD	-31.48

Share Information		Dividend Information	
Shares Outstanding (millions)	22.14	Dividend Yield	5.17%
		Annual Dividend	$1.54
Market Capitalization (millions)	659.62	Payout Ratio	0.50
Short Ratio	3.23	Change in Payout Ratio	-0.15
Last Split Date	03/08/1994	Last Dividend Payout / Amount	03/09/2009 / $0.38

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.34	Current (1=Strong Buy, 5=Strong Sell)	3.25
Current Year EPS Consensus Estimate	2.94	30 Days Ago	3.25
Estimated Long-Term EPS Growth Rate	6.50	60 Days Ago	3.25
Next EPS Report Date	07/24/2009	90 Days Ago	3.25

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	10.14	vs. Previous Year	0.72%	vs. Previous Year	-11.85%
Trailing 12 Months:	9.61	vs. Previous Quarter	-1.41%	vs. Previous Quarter:	-2.25%
PEG Ratio	1.56				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.24	03/31/09	13.53	03/31/09	3.89

Price/Cash Flow	6.93	12/31/08	13.74	12/31/08	3.89
Price / Sales	0.29	09/30/08	12.04	09/30/08	3.35
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.17	03/31/09	0.95	03/31/09	2.97
12/31/08	1.14	12/31/08	0.74	12/31/08	2.83
09/30/08	1.17	09/30/08	0.69	09/30/08	2.53
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	4.46	03/31/09	4.46	03/31/09	24.11
12/31/08	4.20	12/31/08	4.20	12/31/08	22.98
09/30/08	3.79	09/30/08	3.79	09/30/08	22.14
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	11.31	03/31/09	0.73	03/31/09	42.17
12/31/08	12.61	12/31/08	0.77	12/31/08	43.33
09/30/08	13.28	09/30/08	0.80	09/30/08	44.42

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NEW JERSEY RES (NYSE)

Scottrade

NJR 32.33 -0.06 (-0.19%) Vol. 218,797 16:00 ET

NJ RESOURCES is an exempt energy svcs holding company providing retail & wholesale natural gas & related energy services to customers from the Gulf Coast to New England. Subsidiaries include: (1) N J Natural Gas Co, a natural gas distribution company that provides regulated energy & appliance services to residential, commercial & industrial customers in central & northern N J. (2) NJR Energy Holdings Corp formerly NJR Energy Svcs Corp & (3) NJR Development Corp, a sub-holding company of NJR, which includes the Company's remaining unregulated operating subsidiaries.

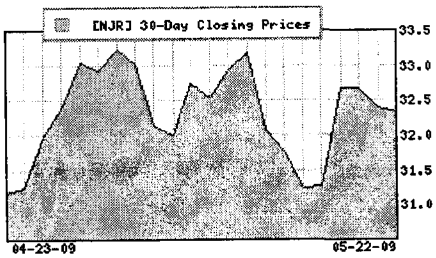
General Information

NJ RESOURCES
1415 Wyckoff Road
Wall, NJ 07719
Phone: 732-938-1489
Fax: 732 938-3154
Web: www.njresources.com
Email: investcont@njresources.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	07/22/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.39
52 Week High	42.37
52 Week Low	21.90
Beta	0.16
20 Day Moving Average	536,252.06
Target Price Consensus	43



% Price Change

4 Week	3.75
12 Week	-8.98
YTD	-17.84

% Price Change Relative to S&P 500

4 Week	-0.35
12 Week	-22.75
YTD	-18.78

Share Information

Shares Outstanding (millions)	42.32
Market Capitalization (millions)	1,368.17
Short Ratio	3.34
Last Split Date	03/04/2008

Dividend Information

Dividend Yield	3.84%
Annual Dividend	$1.24
Payout Ratio	0.63
Change in Payout Ratio	0.12
Last Dividend Payout / Amount	03/11/2009 / $0.31

EPS Information

Current Quarter EPS Consensus Estimate	0.02
Current Year EPS Consensus Estimate	2.39
Estimated Long-Term EPS Growth Rate	8.00
Next EPS Report Date	07/22/2009

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	1.67
30 Days Ago	1.67
60 Days Ago	1.67
90 Days Ago	2.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.53	vs. Previous Year	-8.60%	vs. Previous Year	-20.38%
Trailing 12 Months:	16.41	vs. Previous Quarter	123.68%	vs. Previous Quarter:	17.00%
PEG Ratio	1.69				

Price Ratios		**ROE**		**ROA**	
Price/Book	1.81	03/31/09	11.73	03/31/09	3.25
Price/Cash Flow	10.20	12/31/08	12.89	12/31/08	3.48
Price / Sales	0.38	09/30/08	13.77	09/30/08	3.74
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.17	03/31/09	1.07	03/31/09	2.37
12/31/08	1.17	12/31/08	0.76	12/31/08	2.36
09/30/08	1.24	09/30/08	0.70	09/30/08	2.46
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	5.26	03/31/09	5.26	03/31/09	17.90
12/31/08	3.89	12/31/08	3.89	12/31/08	17.49
09/30/08	4.72	09/30/08	4.72	09/30/08	17.29
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	10.09	03/31/09	0.61	03/31/09	37.74
12/31/08	9.51	12/31/08	0.63	12/31/08	38.48
09/30/08	9.16	09/30/08	0.63	09/30/08	38.50

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NICOR INC (NYSE)				Scottrade	
GAS	30.90	▼-0.18	(-0.58%)	Vol. 288,557	16:01 ET

Nicor Inc. is a holding company and is a member of the Standard & Poor's 500 Index. Its primary business is Nicor Gas, one of the nation's largest natural gas distribution companies. Nicor owns Tropical Shipping, a containerized shipping business serving the Caribbean region and the Bahamas. In addition, the company owns and has an equity interest in several energy-related businesses.

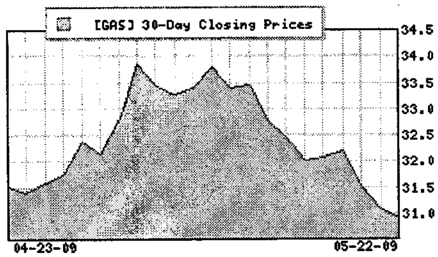
General Information

NICOR INC
1844 Ferry Road
Naperville, IL 60563-9600
Phone: 630-305-9500
Fax: 630-983-9328
Web: www.nicor.com
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	08/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	31.08
52 Week High	51.99
52 Week Low	27.50
Beta	0.36
20 Day Moving Average	519,217.91
Target Price Consensus	40.5



% Price Change

4 Week	-1.94
12 Week	-2.43
YTD	-11.05

% Price Change Relative to S&P 500

4 Week	-5.81
12 Week	-17.19
YTD	-5.73

Share Information

Shares Outstanding (millions)	45.20
Market Capitalization (millions)	1,396.80
Short Ratio	4.13
Last Split Date	04/27/1993

Dividend Information

Dividend Yield	6.02%
Annual Dividend	$1.86
Payout Ratio	0.69
Change in Payout Ratio	-0.05
Last Dividend Payout / Amount	03/27/2009 / $0.47

EPS Information

Current Quarter EPS Consensus Estimate	0.42
Current Year EPS Consensus Estimate	2.55
Estimated Long-Term EPS Growth Rate	5.90
Next EPS Report Date	08/10/2009

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	3.40
30 Days Ago	3.40
60 Days Ago	3.40
90 Days Ago	3.40

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.12	vs. Previous Year	5.49%	vs. Previous Year	-30.39%
Trailing 12 Months:	11.53	vs. Previous Quarter	-8.57%	vs. Previous Quarter:	6.73%
PEG Ratio	2.05				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.39	03/31/09	12.46	03/31/09	2.67

Price/Cash Flow	4.51	12/31/08	12.31	12/31/08	2.62
Price / Sales	0.42	09/30/08	13.19	09/30/08	2.87
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	0.78	03/31/09	0.77	03/31/09	3.70
12/31/08	0.80	12/31/08	0.68	12/31/08	3.16
09/30/08	0.76	09/30/08	0.56	09/30/08	3.48
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	5.21	03/31/09	5.21	03/31/09	22.16
12/31/08	4.34	12/31/08	4.34	12/31/08	21.53
09/30/08	4.80	09/30/08	4.80	09/30/08	21.15
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	15.05	03/31/09	0.45	03/31/09	30.91
12/31/08	18.16	12/31/08	0.46	12/31/08	31.52
09/30/08	23.38	09/30/08	0.47	09/30/08	31.92

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NORTHWEST NAT GAS CO (NYSE)

Scottrade

NWN	39.90	-0.13	(-0.32%)	Vol. 173,466	16:03 ET

NW Natural is principally engaged in the distribution of natural gas.The Oregon Public Utility Commission (OPUC) has allocated to NW Natural as its exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the fertile Willamette Valley and the coastal area from Astoria to Coos Bay. NW Natural also holds certificates from the Washington Utilities and Transportation Commission (WUTC) granting it exclusive rights to serve portions of three Washington counties bordering the Columbia River.

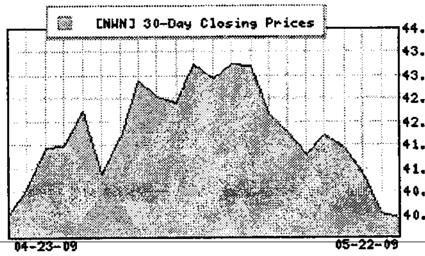
General Information

NORTHWEST NAT G
220 NW Second Avenue
Portland, OR 97209
Phone: 503 226-4211
Fax: 503 273-4824
Web: www.nwnatural.com
Email: Bob.Hess@nwnatural.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	07/17/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	40.03
52 Week High	55.44
52 Week Low	36.61
Beta	0.29
20 Day Moving Average	170,996.70
Target Price Consensus	51.25



% Price Change

4 Week	-0.23
12 Week	-3.20
YTD	-9.79

% Price Change Relative to S&P 500

4 Week	-4.17
12 Week	-17.84
YTD	-4.47

Share Information

Shares Outstanding (millions)	26.50
Market Capitalization (millions)	1,057.39
Short Ratio	7.62
Last Split Date	09/09/1996

Dividend Information

Dividend Yield	3.96%
Annual Dividend	$1.58
Payout Ratio	0.57
Change in Payout Ratio	-0.05
Last Dividend Payout / Amount	04/28/2009 / $0.40

EPS Information

Current Quarter EPS Consensus Estimate	0.17
Current Year EPS Consensus Estimate	2.77
Estimated Long-Term EPS Growth Rate	6.80
Next EPS Report Date	07/17/2009

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.00
30 Days Ago	2.00
60 Days Ago	2.00
90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.39	vs. Previous Year	9.82%	vs. Previous Year	12.81%
Trailing 12 Months:	14.35	vs. Previous Quarter	43.20%	vs. Previous Quarter:	25.24%
PEG Ratio	2.13				

Price Ratios	ROE	ROA

Price/Book	1.59	03/31/09	11.69	03/31/09	3.37
Price/Cash Flow	7.44	12/31/08	11.18	12/31/08	3.31
Price / Sales	0.97	09/30/08	10.77	09/30/08	3.29
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.03	03/31/09	0.80	03/31/09	6.78
12/31/08	0.87	12/31/08	0.70	12/31/08	6.70
09/30/08	0.69	09/30/08	0.44	09/30/08	6.47
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	10.81	03/31/09	10.81	03/31/09	25.05
12/31/08	10.62	12/31/08	10.62	12/31/08	23.77
09/30/08	10.30	09/30/08	10.30	09/30/08	22.88
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	10.10	03/31/09	0.88	03/31/09	46.93
12/31/08	11.16	12/31/08	0.81	12/31/08	44.90
09/30/08	10.09	09/30/08	0.85	09/30/08	45.84

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PIEDMONT NAT GAS INC (NYSE)

Scottrade

PNY	21.81	▾-0.28	(-1.27%)	Vol. 335,349	16:02 ET

Piedmont Natural Gas Co, Inc., is an energy and services company engaged in the transportation and sale of natural gas and the sale of propane to residential, commercial and industrial customers in North Carolina, South Carolina and Tennessee. The Company is the second-largest natural gas utility in the southeast. The Company and its non-utility subsidiaries and divisions are also engaged in acquiring, marketing and arranging for the transportation and storage of natural gas for large-volume purchasers, and in the sale of propane to customers in the Company's three-state service area.

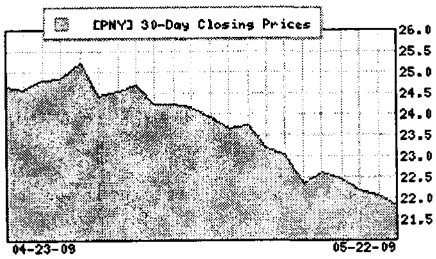
General Information

PIEDMONT NAT GA
4720 Piedmont Row Drive
Charlotte, NC 28210
Phone: 704 364-3120
Fax: 704-365-3849
Web: www.piedmontng.com
Email: investorrelations@piedmontng.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	October
Last Reported Quarter	04/30/09
Next EPS Date	06/08/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	22.09
52 Week High	35.29
52 Week Low	20.52
Beta	0.25
20 Day Moving Average	463,561.66
Target Price Consensus	28.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	-11.52	4 Week	-15.02
12 Week	-10.36	12 Week	-23.92
YTD	-31.13	YTD	-27.83

Share Information		Dividend Information	
Shares Outstanding (millions)	73.48	Dividend Yield	4.95%
		Annual Dividend	$1.08
Market Capitalization (millions)	1,602.69	Payout Ratio	0.00
Short Ratio	9.00	Change in Payout Ratio	0.00
Last Split Date	11/01/2004	Last Dividend Payout / Amount	03/23/2009 / $0.27

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.66	Current (1=Strong Buy, 5=Strong Sell)	2.67
Current Year EPS Consensus Estimate	1.53	30 Days Ago	2.67
Estimated Long-Term EPS Growth Rate	6.50	60 Days Ago	2.67
Next EPS Report Date	06/08/2009	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.22	vs. Previous Year	-1.79%	vs. Previous Year	-1.12%
Trailing 12 Months:	13.89	vs. Previous Quarter	-%	vs. Previous Quarter:	150.08%
PEG Ratio	2.19				

Price Ratios		ROE		ROA	
Price/Book	1.68	04/30/09	-	04/30/09	-
Price/Cash Flow	7.71	01/31/09	11.70	01/31/09	3.55
Price / Sales	-	10/31/08	11.95	10/31/08	3.67
Current Ratio		**Quick Ratio**		**Operating Margin**	
04/30/09	-	04/30/09	-	04/30/09	-
01/31/09	0.99	01/31/09	0.76	01/31/09	5.22
10/31/08	0.88	10/31/08	0.59	10/31/08	5.27
Net Margin		**Pre-Tax Margin**		**Book Value**	
04/30/09	-	04/30/09	-	04/30/09	-
01/31/09	8.66	01/31/09	8.66	01/31/09	12.98
10/31/08	8.78	10/31/08	8.78	10/31/08	12.11
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
04/30/09	-	04/30/09	-	04/30/09	-
01/31/09	10.50	01/31/09	0.83	01/31/09	45.46
10/31/08	11.18	10/31/08	0.90	10/31/08	47.24

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SOUTH JERSEY INDS INC (NYSE)

Scottrade

SJI	33.20	▼-0.29	(-0.87%)	Vol. 177,091	16:03 ET

South Jersey Inds Inc. is engaged in the business of operating, through subsidiaries, various business enterprises. The company's most significant subsidiary is South Jersey Gas Company (SJG). SJG is a public utility company engaged in the purchase, transmission and sale of natural gas for residential, commercial and industrial use. SJG also makes off-system sales of natural gas on a wholesale basis to various customers on the interstate pipeline system and transports natural gas.

General Information

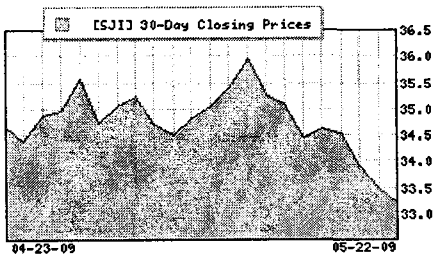
SOUTH JERSEY IN
1 South Jersey Plaza
Folsom, NJ 08037
Phone: 609 561-9000
Fax: 609 561-8225
Web: www.sjindustries.com
Email: investorrelations@sjindustries.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	08/06/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	33.49
52 Week High	40.78
52 Week Low	25.19
Beta	0.26
20 Day Moving Average	229,042.00
Target Price Consensus	41.4



% Price Change		% Price Change Relative to S&P 500	
4 Week	-4.16	4 Week	-7.95
12 Week	-6.14	12 Week	-20.33
YTD	-16.69	YTD	-11.56

Share Information		Dividend Information	
Shares Outstanding (millions)	29.74	Dividend Yield	3.58%
		Annual Dividend	$1.19
Market Capitalization (millions)	987.30	Payout Ratio	0.49
Short Ratio	5.48	Change in Payout Ratio	0.00
Last Split Date	07/01/2005	Last Dividend Payout / Amount	03/06/2009 / $0.30

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.27	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	2.43	30 Days Ago	2.50
Estimated Long-Term EPS Growth Rate	8.40	60 Days Ago	2.67
Next EPS Report Date	08/06/2009	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.64	vs. Previous Year	10.61%	vs. Previous Year	4.06%
Trailing 12 Months:	13.66	vs. Previous Quarter	117.91%	vs. Previous Quarter:	35.30%
PEG Ratio	1.62				

Price Ratios	ROE	ROA

Price/Book	1.82	03/31/09	14.14	03/31/09	4.30
Price/Cash Flow	9.55	12/31/08	13.56	12/31/08	4.16
Price / Sales	1.01	09/30/08	13.53	09/30/08	4.25
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	0.93	03/31/09	0.74	03/31/09	7.43
12/31/08	0.87	12/31/08	0.52	12/31/08	7.07
09/30/08	0.94	09/30/08	0.45	09/30/08	6.99
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	14.51	03/31/09	14.51	03/31/09	18.20
12/31/08	13.40	12/31/08	13.40	12/31/08	17.33
09/30/08	12.52	09/30/08	12.52	09/30/08	17.32
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	5.73	03/31/09	0.61	03/31/09	38.07
12/31/08	6.46	12/31/08	0.65	12/31/08	39.33
09/30/08	6.67	09/30/08	0.69	09/30/08	41.08

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SOUTHWEST GAS CORP (NYSE)

Scottrade

SWX	19.68	▲0.09	(0.46%)	Vol. 320,937	16:02 ET

SOUTHWEST GAS CORP. is principally engaged in the business of purchasing,transporting, and distributing natural gas in portions of Arizona, Nevada,and California. The Company also engaged in financial services activities,through PriMerit Bank, Federal Savings Bank (PriMerit or the Bank), a wholly owned subsidiary.

General Information

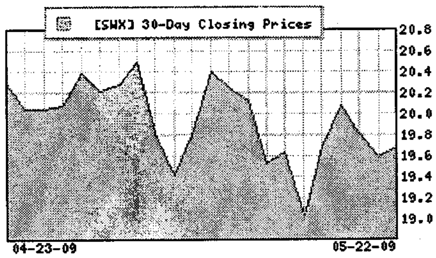
SOUTHWEST GAS
5241 Spring Mountain Road
P.O. Box 98510
Las Vegas, NV 89193-8510
Phone: 702 876-7237
Fax: 702-876-7037
Web: www.swgas.com
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	03/31/09
Next EPS Date	08/05/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	19.59
52 Week High	33.29
52 Week Low	17.08
Beta	0.69
20 Day Moving Average	419,823.44
Target Price Consensus	28



% Price Change

4 Week	-3.01
12 Week	-5.88
YTD	-21.97

% Price Change Relative to S&P 500

4 Week	-6.84
12 Week	-20.12
YTD	-22.80

Share Information

Shares Outstanding (millions)	44.58
Market Capitalization (millions)	877.30
Short Ratio	2.23
Last Split Date	N/A

Dividend Information

Dividend Yield	4.83%
Annual Dividend	$0.95
Payout Ratio	0.65
Change in Payout Ratio	0.12
Last Dividend Payout / Amount	05/13/2009 / $0.24

EPS Information

Current Quarter EPS Consensus Estimate	-0.05
Current Year EPS Consensus Estimate	1.84
Estimated Long-Term EPS Growth Rate	6.00
Next EPS Report Date	08/05/2009

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.60
30 Days Ago	2.60
60 Days Ago	2.60
90 Days Ago	2.60

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	10.71	vs. Previous Year	-1.75%	vs. Previous Year	-15.21%
Trailing 12 Months:	14.16	vs. Previous Quarter	57.75%	vs. Previous Quarter:	35.42%
PEG Ratio	1.79				

Price Ratios		ROE		ROA	
Price/Book	0.81	03/31/09	5.45	03/31/09	1.56

Price/Cash Flow	3.34	12/31/08	5.93	12/31/08	1.69
Price / Sales	0.43	09/30/08	7.18	09/30/08	2.04
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	0.82	03/31/09	0.82	03/31/09	2.81
12/31/08	0.86	12/31/08	0.86	12/31/08	2.84
09/30/08	0.75	09/30/08	0.75	09/30/08	3.32
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	5.09	03/31/09	5.09	03/31/09	24.40
12/31/08	4.75	12/31/08	4.75	12/31/08	23.63
09/30/08	5.37	09/30/08	5.37	09/30/08	23.22
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	-	03/31/09	1.05	03/31/09	51.33
12/31/08	-	12/31/08	1.24	12/31/08	55.33
09/30/08	-	09/30/08	1.20	09/30/08	52.20

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WGL HLDGS INC (NYSE)					Scottrade
WGL	28.83	-0.25	(-0.86%)	Vol. 294,657	16:02 ET

WASHINGTON GAS LIGHT CO is a public utility that delivers and sells natural gas to metropolitan Washington, D.C. and adjoining areas in Maryland and Virginia. A distribution subsidiary serves portions of Virginia and West Virginia. The Company has four wholly-owned active subsidiaries that include: Shenandoah Gas Company (Shenandoah) is engaged in the delivery and sale of natural gas at retail in the Shenandoah Valley, including Winchester, Middletown, Strasburg, Stephens City and New Market, Virginia, and Martinsburg, West Virginia.

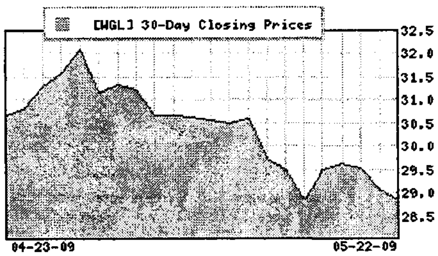
General Information

WGL HLDGS INC
101 Constitution Avenue NW
Washington, DC 20080
Phone: 703 750-2000
Fax: 703 750-4828
Web: www.wglholdings.com
Email: madams@washgas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/09
Next EPS Date	08/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	29.08
52 Week High	37.08
52 Week Low	22.40
Beta	0.24
20 Day Moving Average	463,851.84
Target Price Consensus	34.67



% Price Change		% Price Change Relative to S&P 500	
4 Week	-6.00	4 Week	-9.72
12 Week	-5.26	12 Week	-19.59
YTD	-11.81	YTD	-9.80

Share Information		Dividend Information	
Shares Outstanding (millions)	50.12	Dividend Yield	5.10%
		Annual Dividend	$1.47
Market Capitalization (millions)	1,445.07	Payout Ratio	0.56
Short Ratio	6.94	Change in Payout Ratio	-0.11
Last Split Date	05/02/1995	Last Dividend Payout / Amount	04/07/2009 / $0.37

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.03	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	2.45	30 Days Ago	2.50
Estimated Long-Term EPS Growth Rate	6.70	60 Days Ago	2.50
Next EPS Report Date	08/10/2009	90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.79	vs. Previous Year	-0.60%	vs. Previous Year	2.04%
Trailing 12 Months:	11.44	vs. Previous Quarter	60.19%	vs. Previous Quarter:	26.71%
PEG Ratio	1.77				

Price Ratios	ROE	ROA

Price/Book	1.26	03/31/09	11.60	03/31/09	3.75
Price/Cash Flow	6.69	12/31/08	11.76	12/31/08	3.79
Price / Sales	0.58	09/30/08	11.60	09/30/08	3.72
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/09	1.20	03/31/09	1.04	03/31/09	5.08
12/31/08	1.06	12/31/08	0.70	12/31/08	5.11
09/30/08	0.99	09/30/08	0.42	09/30/08	5.09
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/09	7.58	03/31/09	7.58	03/31/09	22.89
12/31/08	8.04	12/31/08	8.04	12/31/08	21.79
09/30/08	7.08	09/30/08	7.08	09/30/08	20.99
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
03/31/09	8.22	03/31/09	0.57	03/31/09	35.81
12/31/08	7.91	12/31/08	0.60	12/31/08	37.05
09/30/08	8.11	09/30/08	0.58	09/30/08	35.95

ATTACHMENT C

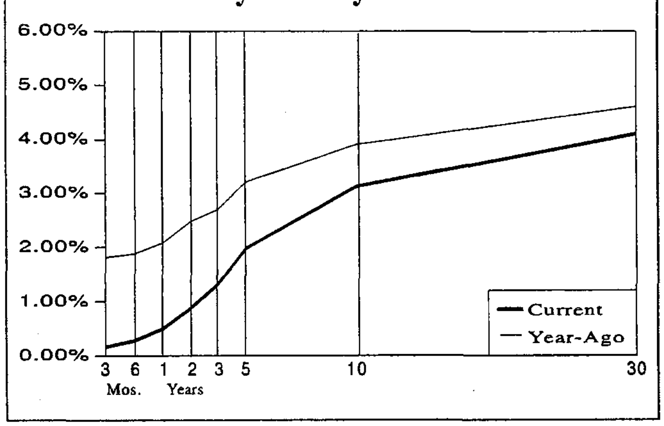
Selected Yields

TAXABLE

	Recent (5/13/09)	3 Months Ago (2/11/09)	Year Ago (5/14/08)
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.32	0.48	2.70
3-month LIBOR	0.88	1.23	2.72
Bank CDs			
6-month	0.73	0.89	1.77
1-year	0.98	1.08	2.05
5-year	1.93	2.37	3.16
U.S. Treasury Securities			
3-month	0.17	0.30	1.82
6-month	0.28	0.45	1.88
1-year	0.50	0.60	2.08
5-year	1.98	1.75	3.20
10-year	3.12	2.75	3.91
10-year (inflation-protected)	1.64	1.60	1.35
30-year	4.10	3.44	4.61
30-year Zero	4.18	3.31	4.71

	Recent (5/13/09)	3 Months Ago (2/11/09)	Year Ago (5/14/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.09	4.02	5.04
FHLMC 6.5% (Gold)	2.38	3.62	5.16
FNMA 6.5%	2.20	3.63	4.90
FNMA ARM	2.78	3.89	4.41
Corporate Bonds			
Financial (10-year) A	6.94	8.09	5.68
Industrial (25/30-year) A	6.19	5.94	6.06
Utility (25/30-year) A	6.01	5.60	6.10
Utility (25/30-year) Baa/BBB	7.57	7.00	6.41
Foreign Bonds (10-Year)			
Canada	3.10	2.94	3.60
Germany	3.34	3.19	4.17
Japan	1.46	1.31	1.68
United Kingdom	3.52	3.61	4.82
Preferred Stocks			
Utility A	6.35	6.01	6.28
Financial A	8.65	11.01	6.75
Financial Adjustable A	5.51	5.51	5.51

Treasury Security Yield Curve



TAX-EXEMPT

	Recent (5/13/09)	3 Months Ago (2/11/09)	Year Ago (5/14/08)
Bond Buyer Indexes			
20-Bond Index (GOs)	4.63	4.96	4.62
25-Bond Index (Revs)	5.57	5.74	5.07
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.55	1.83
1-year A	1.16	0.65	1.93
5-year Aaa	1.82	1.76	2.97
5-year A	3.24	2.02	3.07
10-year Aaa	2.86	2.84	3.62
10-year A	4.41	3.34	3.83
25/30-year Aaa	4.43	4.71	4.55
25/30-year A	5.91	5.75	4.75
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.96	5.75	4.80
Electric AA	6.06	5.80	4.85
Housing AA	6.36	6.10	5.00
Hospital AA	6.31	6.15	5.05
Toll Road Aaa	6.11	5.85	4.85

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/6/09	4/22/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	777464	862387	-84923	731758	706418	385094
Borrowed Reserves	507911	565360	-57449	579211	611473	433308
Net Free/Borrowed Reserves	269553	297027	-27474	152547	94945	-48214

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

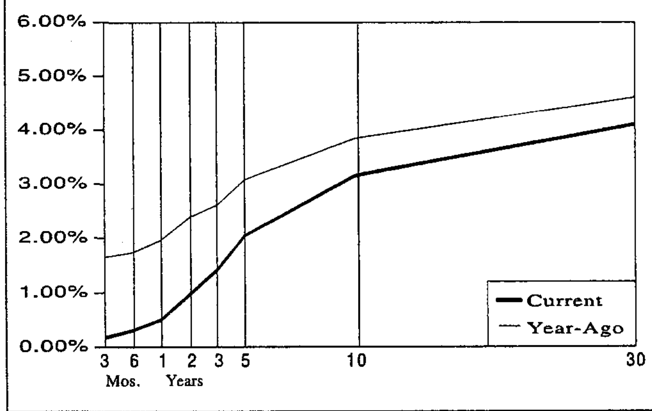
	Recent Levels			Growth Rates Over the Last...		
	4/27/09	4/20/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1576.9	1559.4	17.5	7.3%	12.8%	14.2%
M2 (M1+savings+small time deposits)	8285.2	8243.6	41.6	1.9%	9.5%	8.8%

Selected Yields

	Recent (5/06/09)	3 Months Ago (2/04/09)	Year Ago (5/07/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.40	0.55	2.56
3-month LIBOR	0.97	1.24	2.73
Bank CDs			
6-month	0.79	0.87	1.72
1-year	0.98	1.29	1.99
5-year	1.93	2.41	3.05
U.S. Treasury Securities			
3-month	0.18	0.29	1.66
6-month	0.31	0.40	1.74
1-year	0.50	0.49	1.96
5-year	2.05	1.94	3.08
10-year	3.16	2.94	3.85
10-year (inflation-protected)	1.69	1.78	1.37
30-year	4.10	3.68	4.61
30-year Zero	4.14	3.55	4.68

	Recent (5/06/09)	3 Months Ago (2/04/09)	Year Ago (5/07/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.37	4.28	4.86
FHLMC 6.5% (Gold)	2.91	4.17	5.10
FNMA 6.5%	2.71	4.14	4.84
FNMA ARM	2.78	3.89	4.40
Corporate Bonds			
Financial (10-year) A	7.19	8.03	5.74
Industrial (25/30-year) A	6.31	6.15	6.03
Utility (25/30-year) A	6.10	6.00	6.11
Utility (25/30-year) Baa/BBB	7.54	7.27	6.39
Foreign Bonds (10-Year)			
Canada	3.07	3.12	3.67
Germany	3.24	3.36	4.18
Japan	1.41	1.36	1.67
United Kingdom	3.61	3.77	4.71
Preferred Stocks			
Utility A	6.00	6.02	6.24
Financial A	8.19	10.79	6.73
Financial Adjustable A	5.51	5.51	5.51
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.70	5.16	4.63
25-Bond Index (Revs)	5.57	5.89	5.07
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.55	1.83
1-year A	1.16	0.65	1.93
5-year Aaa	1.84	1.79	3.03
5-year A	3.25	2.09	3.13
10-year Aaa	2.91	2.90	3.70
10-year A	4.45	3.40	3.90
25/30-year Aaa	4.53	4.82	4.62
25/30-year A	6.05	5.82	4.82
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.10	5.90	4.90
Electric AA	6.15	6.00	4.95
Housing AA	6.45	6.25	5.05
Hospital AA	6.40	6.20	5.10
Toll Road Aaa	6.20	6.05	4.95

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 4/22/09	4/8/09	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	862387	804790	57597	733984	671007	356363
Borrowed Reserves	565360	595938	-30578	587381	624561	419423
Net Free/Borrowed Reserves	297027	208852	88175	146604	46446	-63060

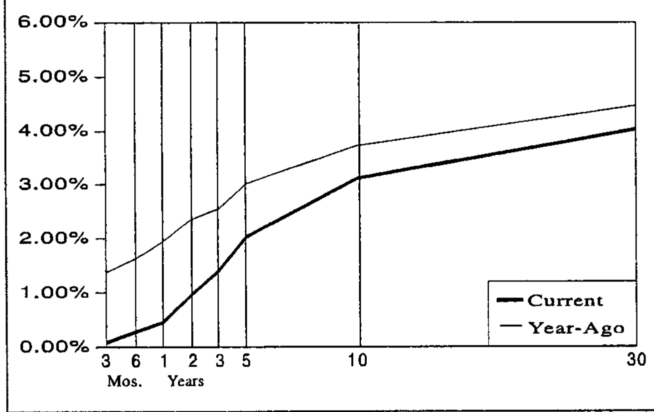
MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 4/20/09	4/13/09	Change	Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1559.4	1576.3	-16.9	2.3%	13.7%	13.1%
M2 (M1+savings+small time deposits)	8244.9	8249.3	-4.4	1.0%	7.9%	8.1%

Selected Yields

	Recent (4/29/09)	3 Months Ago (1/28/09)	Year Ago (4/30/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.40	0.45	2.60
3-month LIBOR	1.03	1.17	2.85
Bank CDs			
6-month	0.79	0.88	1.75
1-year	0.98	1.25	1.77
5-year	1.93	2.39	2.96
U.S. Treasury Securities			
3-month	0.09	0.18	1.38
6-month	0.28	0.33	1.62
1-year	0.46	0.47	1.94
5-year	2.03	1.69	3.01
10-year	3.11	2.67	3.73
10-year (inflation-protected)	1.57	1.78	1.35
30-year	4.03	3.42	4.47
30-year Zero	4.05	3.29	4.54

Treasury Security Yield Curve



	Recent (4/29/09)	3 Months Ago (1/28/09)	Year Ago (4/30/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.30	3.90	5.02
FHLMC 6.5% (Gold)	2.61	3.50	5.21
FNMA 6.5%	2.45	3.50	4.93
FNMA ARM	3.15	4.27	4.40
Corporate Bonds			
Financial (10-year) A	7.84	7.96	5.91
Industrial (25/30-year) A	6.41	6.18	6.00
Utility (25/30-year) A	6.33	6.10	6.12
Utility (25/30-year) Baa/BBB	7.58	7.04	6.31
Foreign Bonds (10-Year)			
Canada	3.08	2.96	3.59
Germany	3.13	3.23	4.12
Japan	1.42	1.27	1.59
United Kingdom	3.46	3.64	4.67
Preferred Stocks			
Utility A	7.53	5.98	6.19
Financial A	8.96	8.89	6.65
Financial Adjustable A	5.50	5.50	5.50
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.57	5.13	4.68
25-Bond Index (Revs)	5.49	5.82	5.01
General Obligation Bonds (GOs)			
1-year Aaa	0.54	0.55	1.80
1-year A	1.04	0.65	1.90
5-year Aaa	1.80	1.84	3.00
5-year A	2.23	2.14	3.10
10-year Aaa	3.19	3.00	3.69
10-year A	3.55	3.50	3.90
25/30-year Aaa	4.67	5.05	4.61
25/30-year A	5.11	6.05	4.81
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.80	6.05	4.90
Electric AA	5.90	6.10	4.95
Housing AA	6.20	6.40	5.05
Hospital AA	6.15	6.45	5.10
Toll Road Aaa	5.95	6.15	4.95

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/22/09	4/8/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	862392	804794	57598	733986	671008	356363
Borrowed Reserves	565360	595938	-30578	587381	624561	419423
Net Free/Borrowed Reserves	297032	208856	88176	146606	46447	-63060

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

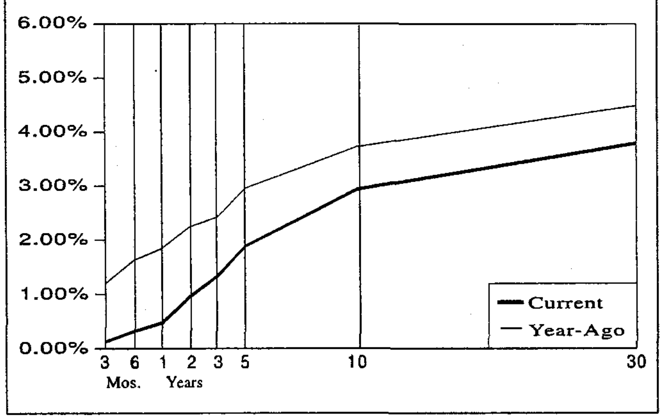
	Recent Levels			Growth Rates Over the Last...		
	4/13/09	4/6/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1576.3	1644.4	-68.1	-6.3%	15.4%	14.8%
M2 (M1+savings+small time deposits)	8249.3	8247.7	1.6	3.0%	9.3%	8.3%

Selected Yields

	Recent (4/22/09)	3 Months Ago (1/21/09)	Year Ago (4/23/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.37	0.55	2.78
3-month LIBOR	1.10	1.13	2.92
Bank CDs			
6-month	0.80	1.03	1.75
1-year	0.99	1.34	1.78
5-year	1.93	2.38	2.95
U.S. Treasury Securities			
3-month	0.13	0.11	1.21
6-month	0.32	0.29	1.63
1-year	0.48	0.43	1.84
5-year	1.89	1.61	2.96
10-year	2.94	2.54	3.73
10-year (inflation-protected)	1.59	1.95	1.29
30-year	3.80	3.16	4.49
30-year Zero	3.79	2.94	4.60

	Recent (4/22/09)	3 Months Ago (1/21/09)	Year Ago (4/23/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.32	3.78	5.11
FHLMC 6.5% (Gold)	2.72	3.53	5.12
FNMA 6.5%	2.58	3.47	4.94
FNMA ARM	3.15	4.25	4.67
Corporate Bonds			
Financial (10-year) A	7.71	7.97	6.03
Industrial (25/30-year) A	6.31	6.05	6.10
Utility (25/30-year) A	6.19	6.03	6.15
Utility (25/30-year) Baa/BBB	7.41	6.66	6.27
Foreign Bonds (10-Year)			
Canada	2.94	2.73	3.67
Germany	3.21	3.00	4.15
Japan	1.44	1.23	1.46
United Kingdom	3.45	3.44	4.67
Preferred Stocks			
Utility A	6.31	6.05	6.03
Financial A	8.98	8.58	6.79
Financial Adjustable A	5.50	5.49	5.50

Treasury Security Yield Curve



	Recent (4/22/09)	3 Months Ago (1/21/09)	Year Ago (4/23/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.78	4.80	4.61
25-Bond Index (Revs)	5.63	5.72	5.04
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.48	1.55
1-year A	1.16	0.58	1.65
5-year Aaa	1.73	1.71	2.85
5-year A	3.15	2.00	2.95
10-year Aaa	2.88	2.82	3.54
10-year A	4.43	3.32	3.75
25/30-year Aaa	4.44	4.76	4.53
25/30-year A	5.95	5.76	4.73
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.00	5.80	4.80
Electric AA	6.10	5.90	4.85
Housing AA	6.40	6.15	4.95
Hospital AA	6.35	6.10	5.00
Toll Road Aaa	6.15	5.95	4.85

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/8/09	3/25/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	804800	771271	33529	731287	619127	324505
Borrowed Reserves	595938	604849	-8911	586952	622967	403815
Net Free/Borrowed Reserves	208862	166422	42440	144335	-3841	-79310

MONEY SUPPLY

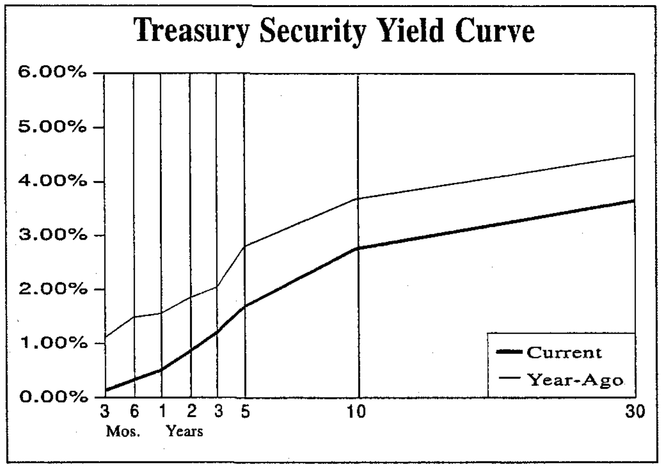
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/6/09	3/30/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1641.2	1551.3	89.9	1.0%	26.6%	20.5%
M2 (M1+savings+small time deposits)	8244.7	8308.2	-63.5	3.3%	10.4%	8.2%

Selected Yields

	Recent (4/15/09)	3 Months Ago (1/14/09)	Year Ago (4/16/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.38	0.49	2.56
3-month LIBOR	1.11	1.08	2.73
Bank CDs			
6-month	0.81	1.03	1.76
1-year	1.02	1.34	1.79
5-year	2.01	2.38	2.87
U.S. Treasury Securities			
3-month	0.14	0.09	1.12
6-month	0.33	0.27	1.49
1-year	0.51	0.41	1.56
5-year	1.70	1.35	2.81
10-year	2.76	2.20	3.69
10-year (inflation-protected)	1.43	1.73	1.21
30-year	3.66	2.89	4.49
30-year Zero	3.66	2.75	4.62

	Recent (4/15/09)	3 Months Ago (1/14/09)	Year Ago (4/16/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.39	3.93	4.90
FHLMC 6.5% (Gold)	2.67	3.25	5.14
FNMA 6.5%	2.62	3.30	4.81
FNMA ARM	3.15	4.26	4.66
Corporate Bonds			
Financial (10-year) A	7.61	7.15	6.11
Industrial (25/30-year) A	6.25	5.84	6.12
Utility (25/30-year) A	6.17	5.88	6.28
Utility (25/30-year) Baa/BBB	7.59	6.60	6.40
Foreign Bonds (10-Year)			
Canada	2.94	2.56	3.68
Germany	3.14	2.93	4.04
Japan	1.44	1.27	1.35
United Kingdom	3.26	3.12	4.53
Preferred Stocks			
Utility A	6.36	6.05	6.06
Financial A	7.55	7.76	6.71
Financial Adjustable A	5.49	5.49	5.49



	Recent (4/15/09)	3 Months Ago (1/14/09)	Year Ago (4/16/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.92	5.02	4.61
25-Bond Index (Revs)	5.74	5.90	5.04
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.48	1.55
1-year A	0.53	0.58	1.65
5-year Aaa	1.91	1.76	2.85
5-year A	2.13	2.06	2.95
10-year Aaa	3.09	2.82	3.54
10-year A	3.62	3.32	3.75
25/30-year Aaa	4.71	4.75	4.53
25/30-year A	5.75	5.75	4.73
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.70	5.75	4.80
Electric AA	5.80	5.80	4.85
Housing AA	6.10	6.10	4.95
Hospital AA	6.15	6.15	5.00
Toll Road Aaa	5.85	5.85	4.85

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/8/09	3/25/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	804805	771269	33536	731288	619127	324505
Borrowed Reserves	595938	604849	-8911	586952	622967	403815
Net Free/Borrowed Reserves	208867	166420	42447	144336	-3840	-79310

MONEY SUPPLY

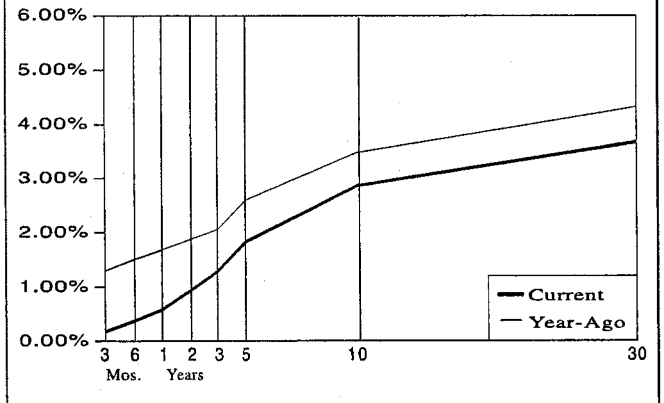
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/30/09	3/23/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1551.1	1549.4	1.7	-10.7%	8.2%	13.1%
M2 (M1+savings+small time deposits)	8308.0	8336.5	-28.5	7.3%	10.8%	9.1%

Selected Yields

	Recent (4/08/09)	3 Months Ago (1/07/09)	Year Ago (4/09/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.33	0.65	2.63
3-month LIBOR	1.14	1.40	2.72
Bank CDs			
6-month	0.83	1.10	1.76
1-year	1.04	1.41	1.79
5-year	2.05	2.38	2.87
U.S. Treasury Securities			
3-month	0.18	0.09	1.30
6-month	0.37	0.28	1.50
1-year	0.58	0.41	1.68
5-year	1.83	1.66	2.60
10-year	2.86	2.49	3.48
10-year (inflation-protected)	1.53	2.44	1.07
30-year	3.67	3.04	4.32
30-year Zero	3.67	2.87	4.43

Treasury Security Yield Curve



	Recent (4/08/09)	3 Months Ago (1/07/09)	Year Ago (4/09/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.40	4.30	4.52
FHLMC 6.5% (Gold)	2.79	3.95	4.89
FNMA 6.5%	2.79	3.75	4.58
FNMA ARM	3.15	4.26	4.67
Corporate Bonds			
Financial (10-year) A	7.85	7.56	6.06
Industrial (25/30-year) A	6.27	6.26	5.93
Utility (25/30-year) A	6.20	6.07	6.14
Utility (25/30-year) Baa/BBB	7.63	6.72	6.28
Foreign Bonds (10-Year)			
Canada	2.90	2.93	3.56
Germany	3.21	3.20	4.01
Japan	1.46	1.26	1.35
United Kingdom	3.35	3.29	4.51
Preferred Stocks			
Utility A	6.35	6.11	6.06
Financial A	7.80	7.28	6.60
Financial Adjustable A	5.48	5.48	5.48
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.95	5.24	4.90
25-Bond Index (Revs)	5.75	6.00	5.18
General Obligation Bonds (GOs)			
1-year Aaa	0.47	0.85	1.55
1-year A	1.20	0.95	1.70
5-year Aaa	2.03	2.48	2.94
5-year A	3.45	2.77	3.05
10-year Aaa	3.20	3.53	3.70
10-year A	4.75	4.03	3.90
25/30-year Aaa	4.77	5.04	4.78
25/30-year A	6.25	6.04	4.98
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.30	6.10	5.05
Electric AA	6.40	6.25	5.05
Housing AA	6.70	6.55	5.35
Hospital AA	6.65	6.50	5.30
Toll Road Aaa	6.45	6.25	5.10

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	3/25/09	3/11/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	771276	621568	149708	730382	566553	294869
Borrowed Reserves	604849	630177	-25328	591508	599533	385679
Net Free/Borrowed Reserves	166427	-8609	175036	138874	-32980	-90810

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

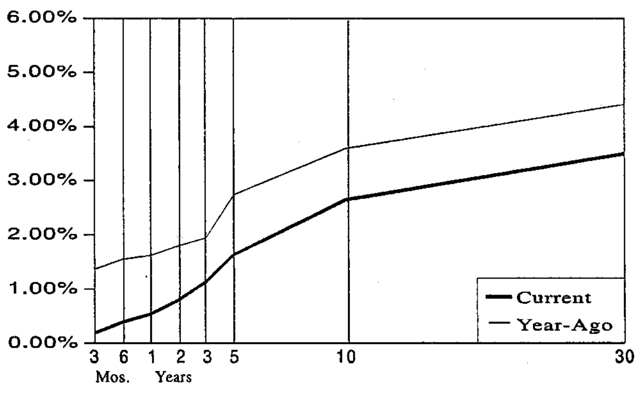
	Recent Levels			Growth Rates Over the Last...		
	3/23/09	3/16/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1551.1	1564.0	-12.9	-11.2%	10.8%	13.3%
M2 (M1+savings+small time deposits)	8372.3	8375.2	-2.9	10.1%	12.8%	9.9%

Selected Yields

	Recent (4/01/09)	3 Months Ago (12/30/08)	Year Ago (4/02/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.44	0.06	2.67
3-month LIBOR	1.18	1.44	2.70
Bank CDs			
6-month	0.83	1.16	1.78
1-year	1.04	1.43	1.76
5-year	2.06	2.51	2.87
U.S. Treasury Securities			
3-month	0.20	0.09	1.37
6-month	0.39	0.24	1.55
1-year	0.54	0.31	1.62
5-year	1.64	1.44	2.74
10-year	2.65	2.05	3.60
10-year (inflation-protected)	1.32	2.33	1.12
30-year	3.50	2.56	4.41
30-year Zero	3.52	2.42	4.48

	Recent (4/01/09)	3 Months Ago (12/30/08)	Year Ago (4/02/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.53	4.11	4.81
FHLMC 6.5% (Gold)	3.12	4.03	5.05
FNMA 6.5%	3.04	3.89	4.79
FNMA ARM	3.15	4.22	4.67
Corporate Bonds			
Financial (10-year) A	7.49	7.08	6.30
Industrial (25/30-year) A	6.17	5.90	6.07
Utility (25/30-year) A	5.99	5.85	6.16
Utility (25/30-year) Baa/BBB	7.41	6.58	6.25
Foreign Bonds (10-Year)			
Canada	2.78	2.66	3.63
Germany	2.99	2.95	3.99
Japan	1.35	1.17	1.37
United Kingdom	3.13	3.09	4.43
Preferred Stocks			
Utility A	6.74	6.00	6.16
Financial A	9.90	7.89	6.74
Financial Adjustable A	5.48	5.48	5.48

Treasury Security Yield Curve



	Recent (4/01/09)	3 Months Ago (12/30/08)	Year Ago (4/02/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	5.00	5.46	4.96
25-Bond Index (Revs)	5.78	6.22	5.24
General Obligation Bonds (GOs)			
1-year Aaa	0.50	0.85	1.60
1-year A	0.60	0.95	1.70
5-year Aaa	2.08	2.57	3.00
5-year A	2.33	2.87	3.10
10-year Aaa	3.20	3.70	3.79
10-year A	3.73	4.20	4.00
25/30-year Aaa	4.79	5.17	4.91
25/30-year A	5.83	6.15	5.11
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.80	6.15	5.20
Electric AA	5.85	6.20	5.25
Housing AA	6.15	6.50	5.35
Hospital AA	6.20	6.55	5.40
Toll Road Aaa	5.90	6.25	5.25

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	3/25/09	3/11/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	771194	621518	149676	730364	566544	294864
Borrowed Reserves	604849	630177	-25328	591508	599533	385679
Net Free/Borrowed Reserves	166345	-8659	175004	138856	-32990	-90815

MONEY SUPPLY

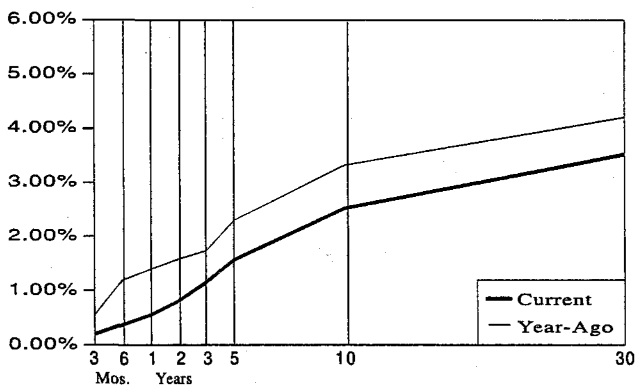
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/16/09	3/9/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1565.6	1577.1	-11.5	-8.4%	19.8%	14.4%
M2 (M1+savings+small time deposits)	8376.2	8342.9	33.3	12.1%	18.2%	10.2%

Selected Yields

	Recent (3/25/09)	3 Months Ago (12/23/08)	Year Ago (3/26/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.50
Federal Funds	0.00-0.25	0.00-0.25	2.25
Prime Rate	3.25	3.25	5.25
30-day CP (A1/P1)	0.51	0.10	2.83
3-month LIBOR	1.23	1.47	2.67
Bank CDs			
6-month	0.83	1.17	1.84
1-year	1.04	1.56	1.84
5-year	2.06	2.72	2.87
U.S. Treasury Securities			
3-month	0.18	0.01	1.27
6-month	0.40	0.23	1.46
1-year	0.58	0.35	1.64
5-year	1.81	1.50	2.49
10-year	2.78	2.16	3.46
10-year (inflation-protected)	1.38	2.36	1.10
30-year	3.74	2.63	4.31
30-year Zero	3.77	2.67	4.45

Treasury Security Yield Curve



	Recent (3/25/09)	3 Months Ago (12/23/08)	Year Ago (3/26/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.48	4.43	4.35
FHLMC 6.5% (Gold)	2.99	4.38	4.99
FNMA 6.5%	3.00	4.16	4.74
FNMA ARM	3.60	4.23	5.08
Corporate Bonds			
Financial (10-year) A	7.51	7.08	6.06
Industrial (25/30-year) A	6.48	6.02	6.11
Utility (25/30-year) A	6.28	5.90	6.03
Utility (25/30-year) Baa/BBB	7.71	7.07	6.24
Foreign Bonds (10-Year)			
Canada	2.96	2.80	3.47
Germany	3.15	2.95	3.88
Japan	1.29	1.22	1.28
United Kingdom	3.28	3.12	4.44
Preferred Stocks			
Utility A	6.11	6.25	6.02
Financial A	9.42	11.45	6.75
Financial Adjustable A	5.47	5.47	5.47
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.98	5.46	4.88
25-Bond Index (Revs)	5.81	6.22	5.17
General Obligation Bonds (GOs)			
1-year Aaa	0.50	0.85	1.70
1-year A	0.60	0.95	1.85
5-year Aaa	2.15	2.57	2.85
5-year A	2.45	2.87	2.95
10-year Aaa	3.24	3.70	3.74
10-year A	3.74	4.20	3.94
25/30-year Aaa	4.85	5.17	4.95
25/30-year A	5.85	6.15	5.15
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.90	6.15	5.20
Electric AA	6.00	6.20	5.20
Housing AA	6.30	6.50	5.50
Hospital AA	6.25	6.55	5.45
Toll Road Aaa	6.05	6.25	5.20

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	3/11/09	2/25/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	621518	673434	-51916	730828	511620	266354
Borrowed Reserves	630177	588910	41267	601461	568436	365508
Net Free/Borrowed Reserves	-8659	84524	-93183	129367	-56816	-99154

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/9/09	3/2/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1577.1	1561.3	15.8	-0.2%	24.5%	14.5%
M2 (M1+savings+small time deposits)	8343.1	8303.3	39.8	12.8%	17.8%	10.1%

UNS GAS, INC.

DOCKET NO. G-04204A-08-0571

TABLE OF CONTENTS TO SCHEDULES WAR

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
COST OF CAPITAL SUMMARY

ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	LONG-TERM DEBT	99,265	-	99,265	50.01%	6.49%	3.25%
3	COMMON EQUITY	99,242	-	99,242	49.99%	8.61%	4.30%
4	TOTAL CAPITALIZATION	$ 198,507	$ -	$ 198,507	100.00%		
5	**ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL**						7.55%

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
COST OF CAPITAL SUMMARY

WEIGHTED COST OF DEBT

LINE NO.	(A) DESCRIPTION	(B) BALANCE	(C) ANNUAL INTEREST	(D) INTEREST RATE	(E) BALANCE RATIOS	(F) WEIGHTED COST OF DEBT
1	UNS GAS SERIES A BONDS	$ 50,000	$ 3,115	6.23%	50.00%	3.115%
2	UNS GAS SERIES B BONDS	50,000	3,115	6.23%	50.00%	3.115%
3	TOTALS	$ 100,000	$ 6,230		100.00%	6.23%
4	UNAMORTIZED DEBT DISCOUNT, PREMIUM AND EXPENSE ON REAQUIRED DEBT	$ (735)				
5	AMORTIZATION OF DEBT DISCOUNT AND EXPENSE AND LOSS ON REAQUIRED DEBT		$ 170			
6	CREDIT FACILITY COMMITMENT FEES		43			
7	TOTAL COST OF LONG-TERM DEBT - NET	$ 99,265	$ 6,443	6.49%	100.00%	
8	**WEIGHTED COST OF DEBT**					**6.49%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2, PAGE 2
COLUMN (B): COMPANY SCHEDULE D-2, PAGE 2
COLUMN (C): COMPANY SCHEDULE D-2, PAGE 2
COLUMN (D): COLUMN (C) ÷ COLUMN (D)
COLUMN (E): COLUMN (A) LINES 1 AND 2 ÷ LINE 3
COLUMN (F): COLUMN (D) x COLUMN (E)

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	DCF METHODOLOGY		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	11.40%	SCHEDULE WAR-2, COLUMN (C), LINE 11
3	CAPM METHODOLOGY		
4	CAPM - GEOMETRIC MEAN ESTIMATE	5.26%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 11
5	CAPM - ARITHMETIC MEAN ESTIMATE	6.39%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 11
6	AVERAGE OF CAPM ESTIMATES	5.82%	(LINE 4 + LINE 5) ÷ 2
7	**AVERAGE OF DCF AND CAPM ESTIMATES**	**8.61%**	(LINE 2 + LINE 6) ÷ 2

INFLATION ADJUSTMENT TO RUCO'S RECOMMENDED ORIGINAL COST OF EQUITY CAPITAL

LINE NO.	(A) YEAR	(B) VALUE TIPS	(C) VALUE BONDS	(D) DIFFERENCE
1	2001	3.31%	5.02%	1.71%
2	2002	2.85%	4.61%	1.76%
3	2003	1.81%	4.01%	2.20%
4	2004	1.37%	4.27%	2.90%
5	2005	1.53%	4.29%	2.76%
6	2006	2.25%	4.80%	2.55%
7	2007	2.10%	4.63%	2.53%
8	2008	0.13%	3.79%	3.66%
9	AVERAGE	1.92%	4.43%	2.51%
10	**INFLATION ADJUSTMENT TO RUCO'S RECOMMENDED ORIGINAL COST OF EQUITY CAPITAL**			**2.50%**

REFERENCES

COLUMNS (A), (B) AND (C): FEDERAL RESERVE BANK OF ST. LOUIS WEBSITE
COLUMN (D): COLUMN (C) - COLUMN (D)

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
DCF COST OF EQUITY CAPITAL

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	AGL	AGL RESOURCES, INC.	6.07%	+	5.58%	=	11.64%
2	ATO	ATMOS ENERGY CORPORATION	5.55%	+	11.03%	=	16.58%
3	LG	LACLEDE GROUP, INC.	4.41%	+	5.28%	=	9.69%
4	NJR	NEW JERSEY RESOURCES CORP.	3.81%	+	5.71%	=	9.52%
5	GAS	NICOR, INC.	5.72%	+	5.02%	=	10.74%
6	NWN	NORTHWEST NATURAL GAS CO.	3.78%	+	4.94%	=	8.72%
7	PNY	PIEDMONT NATURAL GAS COMPANY	4.24%	+	5.50%	=	9.75%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	6.51%	+	7.90%	=	14.42%
9	SWX	SOUTHWEST GAS CORP.	4.71%	+	9.03%	=	13.74%
10	WGL	WGL HOLDINGS, INC.	4.67%	+	4.52%	=	9.19%
11	**NATURAL GAS LDC AVERAGE**						**11.40%**

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
DIVIDEND YIELD CALCULATION

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	AGL	AGL RESOURCES, INC.	$1.72	÷	$28.35	=	6.07%
2	ATO	ATMOS ENERGY CORPORATION	1.32	÷	23.79	=	5.55%
3	LG	LACLEDE GROUP, INC.	1.54	÷	34.89	=	4.41%
4	NJR	NEW JERSEY RESOURCES CORP.	1.24	÷	32.51	=	3.81%
5	GAS	NICOR, INC.	1.86	÷	32.52	=	5.72%
6	NWN	NORTHWEST NATURAL GAS CO.	1.58	÷	41.80	=	3.78%
7	PNY	PIEDMONT NATURAL GAS COMPANY	1.04	÷	24.50	=	4.24%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	2.27	÷	34.87	=	6.51%
9	SWX	SOUTHWEST GAS CORP.	0.95	÷	20.23	=	4.71%
10	WGL	WGL HOLDINGS, INC.	1.44	÷	30.85	=	4.67%
11	**NATURAL GAS LDC AVERAGE**						**4.95%**

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/13/2009.
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 03/30/2009 TO 05/22/2009 STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 4

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	AGL	AGL RESOURCES, INC.	5.30%	+	0.28%	=	5.58%
2	ATO	ATMOS ENERGY CORPORATION	4.05%	+	6.98%	=	11.03%
3	LG	LACLEDE GROUP, INC.	4.50%	+	0.78%	=	5.28%
4	NJR	NEW JERSEY RESOURCES CORP.	5.25%	+	0.46%	=	5.71%
5	GAS	NICOR, INC.	5.00%	+	0.02%	=	5.02%
6	NWN	NORTHWEST NATURAL GAS CO.	4.60%	+	0.34%	=	4.94%
7	PNY	PIEDMONT NATURAL GAS COMPANY	5.50%	+	0.00%	=	5.50%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	7.00%	+	0.90%	=	7.90%
9	SWX	SOUTHWEST GAS CORP.	4.25%	+	4.78%	=	9.03%
10	WGL	WGL HOLDINGS, INC.	4.50%	+	0.02%	=	4.52%
11	**NATURAL GAS LDC AVERAGE**						**6.45%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 4

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) ÷ 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	AGL	AGL RESOURCES, INC.	1.75%	x	{ [((1.32) + 1) ÷ 2] - 1 }	=	0.28%
2	ATO	ATMOS ENERGY CORPORATION	3.50%	x	{ [((0.99) + 1) ÷ 2] + 1 }	=	6.98%
3	LG	LACLEDE GROUP, INC.	3.25%	x	{ [((1.48) + 1) ÷ 2] - 1 }	=	0.78%
4	NJR	NEW JERSEY RESOURCES CORP.	1.25%	x	{ [((1.73) + 1) ÷ 2] - 1 }	=	0.46%
5	GAS	NICOR, INC.	0.10%	x	{ [((1.46) + 1) ÷ 2] - 1 }	=	0.02%
6	NWN	NORTHWEST NATURAL GAS CO.	1.00%	x	{ [((1.68) + 1) ÷ 2] - 1 }	=	0.34%
7	PNY	PIEDMONT NATURAL GAS COMPANY	0.01%	x	{ [((1.94) + 1) ÷ 2] - 1 }	=	0.00%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	2.00%	x	{ [((1.90) + 1) ÷ 2] - 1 }	=	0.90%
9	SWX	SOUTHWEST GAS CORP.	2.50%	x	{ [((0.83) + 1) ÷ 2] + 1 }	=	4.78%
10	WGL	WGL HOLDINGS, INC.	0.10%	x	{ [((1.40) + 1) ÷ 2] - 1 }	=	0.02%
11	**NATURAL GAS LDC AVERAGE**						**1.46%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 03/13/2009
COLUMN (C): COLUMN (A) x COLUMN (B)

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
DIVIDEND GROWTH COMPONENTS

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 5

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION 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	AGL	AGL RESOURCES, INC.	2004	0.4956		11.00%		5.45%	18.06	76.70	
2			2005	0.4758		12.90%		6.14%	19.29	77.70	
3			2006	0.4559		13.20%		6.02%	20.71	77.70	
4			2007	0.3971		12.70%		5.04%	21.74	76.40	
5			2008	0.3801		12.60%		4.79%	21.48	76.90	
6			GROWTH 2002 - 2008					5.49%	11.50%		0.07%
7			2009	0.3630		12.50%		4.54%		78.00	1.43%
8			2010	0.3825		13.00%		4.97%		79.00	1.36%
9			2012-14	0.4125		14.50%		5.98%	0.50%	85.00	2.02%
10											
11	ATO	ATMOS ENERGY CORPORATION	2004	0.2278		7.60%		1.73%	18.05	62.80	
12			2005	0.2791		8.50%		2.37%	19.90	80.54	
13			2006	0.3700		9.80%		3.63%	20.16	81.74	
14			2007	0.3402		8.70%		2.96%	22.01	89.33	
15			2008	0.3500		8.80%		3.08%	22.60	90.81	
16			GROWTH 2002 - 2008					2.75%	7.50%		9.66%
17			2009	0.3714		9.00%		3.34%		92.00	1.31%
18			2010	0.3767		8.50%		3.20%		93.00	1.20%
19			2012-14	0.4400		9.50%		4.18%	4.00%	110.00	3.91%
20											
21	LG	LACLEDE GROUP, INC.	2004	0.2582		10.10%		2.61%	16.96	20.98	
22			2005	0.2789		10.90%		3.04%	17.31	21.17	
23			2006	0.4093		12.50%		5.12%	18.85	21.36	
24			2007	0.3723		11.60%		4.32%	19.79	21.65	
25			2008	0.4356		11.80%		5.14%	22.12	21.99	
26			GROWTH 2002 - 2008					4.04%	5.50%		1.18%
27			2009	0.4632		12.50%		5.79%		22.50	2.32%
28			2010	0.3962		10.50%		4.16%		23.00	2.27%
29			2012-14	0.4333		11.00%		4.77%	5.50%	26.00	3.41%
30											
31	NJR	NEW JERSEY RESOURCES CORP.	2004	0.4882		15.30%		7.47%	11.25	41.61	
32			2005	0.4859		17.00%		8.26%	10.60	41.32	
33			2006	0.4866		12.60%		6.13%	15.00	41.44	
34			2007	0.3484		10.10%		3.52%	15.50	41.61	
35			2008	0.5889		15.70%		9.25%	17.28	42.06	
36			GROWTH 2002 - 2008					6.93%	11.50%		0.27%
37			2009	0.5040		13.50%		6.80%		42.50	1.05%
38			2010	0.5259		13.00%		6.84%		43.00	1.11%
39			2012-14	0.5088		11.00%		5.60%	8.50%	45.00	1.36%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 03/13/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008
COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION 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	GAS	NICOR, INC.	2004	0.1622	13.10%	2.12%	16.99	44.10	
2			2005	0.1806	12.50%	2.26%	18.36	44.18	
3			2006	0.3519	14.70%	5.17%	19.43	44.90	
4			2007	0.3779	14.30%	5.40%	20.58	45.90	
5			2008	0.2928	12.30%	3.60%	21.55	45.13	
6			GROWTH 2002 - 2008			3.71%	4.00%		0.58%
7			2009	0.2560	11.00%	2.82%		45.00	-0.29%
8			2010	0.3586	12.50%	4.48%		45.00	-0.14%
9			2012-14	0.4364	12.00%	5.24%	4.50%	45.00	-0.06%
10									
11	NWN	NORTHWEST NATURAL GAS CO.	2004	0.3011	8.90%	2.68%	20.64	27.55	
12			2005	0.3744	9.90%	3.71%	21.28	27.58	
13			2006	0.4085	10.90%	4.45%	22.01	27.24	
14			2007	0.4783	12.50%	5.98%	22.52	26.41	
15			2008	0.4109	11.20%	4.60%	23.70	26.50	
16			GROWTH 2002 - 2008			4.28%	3.50%		-0.97%
17			2009	0.4255	11.00%	4.68%		26.50	0.00%
18			2010	0.4175	11.00%	4.59%		26.50	0.00%
19			2012-14	0.4203	11.00%	4.62%	3.50%	28.00	1.11%
20									
21	PNY	PIEDMONT NATURAL GAS COMPANY	2004	0.3307	11.10%	3.67%	11.15	76.67	
22			2005	0.3106	11.50%	3.57%	11.53	76.70	
23			2006	0.2578	11.00%	2.84%	11.83	74.61	
24			2007	0.2929	11.90%	3.49%	11.99	73.23	
25			2008	0.3087	12.40%	3.83%	12.11	73.26	
26			GROWTH 2002 - 2008			3.48%	6.00%		-1.13%
27			2009	0.3438	12.50%	4.30%		73.50	0.33%
28			2010	0.3889	13.50%	5.25%		73.50	0.16%
29			2012-14	0.4186	13.50%	5.65%	5.00%	73.00	-0.07%
30									
31	SJI	SOUTH JERSEY INDUSTIES, INC.	2004	0.4810	12.50%	6.01%	12.41	27.76	
32			2005	0.4971	12.40%	6.16%	13.50	28.98	
33			2006	0.6260	16.30%	10.20%	15.11	29.33	
34			2007	0.5167	12.80%	6.61%	16.25	29.61	
35			2008	0.5110	13.20%	6.75%	17.33	29.73	
36			GROWTH 2002 - 2008			7.15%	12.50%		1.73%
37			2009	0.5102	13.50%	6.89%		30.50	2.59%
38			2010	0.5170	13.50%	6.98%		31.00	2.11%
39			2012-14	0.5161	14.50%	7.48%	4.50%	33.00	2.11%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 03/13/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION 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	SWX	SOUTHWEST GAS CORP.	2004	0.5060		8.30%		4.20%	19.18	36.79	
2			2005	0.3440		6.40%		2.20%	19.10	39.33	
3			2006	0.5859		8.90%		5.21%	21.58	41.77	
4			2007	0.5590		8.50%		4.75%	22.98	42.81	
5			2008	0.3525		5.90%		2.08%	23.48	44.19	
6			GROWTH 2002 - 2008					3.69%	4.00%		4.69%
7			2009	0.3667		6.00%		2.20%		45.00	1.83%
8			2010	0.4595		7.50%		3.45%		46.00	2.03%
9			2012-14	0.5000		9.00%		4.50%	2.50%	50.00	2.50%
10											
11	WGL	WGL HOLDINGS, INC.	2004	0.3434		11.70%		4.02%	16.95	48.67	
12			2005	0.3803		11.70%		4.45%	17.80	48.65	
13			2006	0.3041		10.30%		3.13%	18.86	48.89	
14			2007	0.3476		10.40%		3.62%	19.83	49.45	
15			2008	0.4221		11.60%		4.90%	20.99	49.92	
16			GROWTH 2002 - 2008					4.02%	4.50%		0.64%
17			2009	0.4200		12.00%		5.04%		50.00	0.16%
18			2010	0.4118		11.50%		4.74%		50.00	0.08%
19			2012-14	0.4182		11.00%		4.60%	5.00%	50.00	0.03%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 03/13/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6 & 16, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6 & 16, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
GROWTH RATE COMPARISON

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 6

LINE	STOCK	(A)	(B) ZACKS	(C) VALUE LINE PROJECTED			(D) VALUE LINE HISTORIC			(E) VALUE LINE &	(F) 5 - YEAR COMPOUND HISTORY		
NO.	SYMBOL	(br) + (sv)	EPS	EPS	DPS	BVPS	EPS	DPS	BVPS	ZACKS AVGS.	EPS	DPS	BVPS
1	AGL	5.58%	5.30%	3.00%	2.50%	0.50%	11.50%	6.50%	11.50%	5.83%	4.41%	9.94%	4.43%
2	ATO	11.03%	5.80%	4.00%	1.50%	4.00%	5.00%	1.50%	7.50%	4.19%	9.74%	2.50%	6.87%
3	LG	5.28%	6.50%	3.50%	2.50%	5.50%	9.50%	1.50%	5.50%	4.93%	4.33%	0.00%	6.12%
4	NJR	5.71%	8.00%	5.50%	5.50%	8.50%	7.50%	5.00%	11.50%	7.36%	4.07%	4.92%	2.09%
5	GAS	5.02%	5.90%	2.50%	-	4.50%	1.00%	0.50%	4.00%	3.07%	-4.34%	2.35%	5.19%
6	NWN	4.94%	6.80%	7.00%	5.50%	3.50%	6.50%	2.00%	3.50%	4.97%	5.99%	4.15%	5.95%
7	PNY	5.50%	6.50%	7.50%	3.50%	5.00%	6.50%	4.50%	6.00%	5.64%	0.00%	0.00%	0.00%
8	SJI	7.90%	8.40%	5.50%	7.00%	4.50%	12.50%	4.50%	12.50%	7.84%	0.00%	0.00%	0.00%
9	SWX	9.03%	6.00%	4.50%	5.00%	2.50%	8.00%	0.50%	4.00%	4.36%	0.00%	0.00%	0.00%
10	WGL	4.52%	6.70%	4.00%	2.50%	5.00%	4.00%	1.50%	4.50%	4.03%	0.00%	0.00%	0.00%
11				4.70%	3.94%	4.35%	7.20%	2.80%	7.05%		2.42%	2.39%	3.06%
12	AVERAGES	6.45%	6.59%		4.33%			5.68%		5.22%		2.62%	

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 03/13/2009
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/13/2006
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THRU 10
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/13/2009

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
CAPM COST OF EQUITY CAPITAL

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AGL	k	=	1.87%	+ [	0.75	x (	10.40%	-	5.30%	)]	=	5.69%
2	ATO	k	=	1.87%	+ [	0.60	x (	10.40%	-	5.30%	)]	=	4.93%
3	LG	k	=	1.87%	+ [	0.65	x (	10.40%	-	5.30%	)]	=	5.18%
4	NJR	k	=	1.87%	+ [	0.65	x (	10.40%	-	5.30%	)]	=	5.18%
5	GAS	k	=	1.87%	+ [	0.75	x (	10.40%	-	5.30%	)]	=	5.69%
6	NWN	k	=	1.87%	+ [	0.60	x (	10.40%	-	5.30%	)]	=	4.93%
7	PNY	k	=	1.87%	+ [	0.65	x (	10.40%	-	5.30%	)]	=	5.18%
8	SJI	k	=	1.87%	+ [	0.65	x (	10.40%	-	5.30%	)]	=	5.18%
9	SWX	k	=	1.87%	+ [	0.70	x (	10.40%	-	5.30%	)]	=	5.44%
10	WGL	k	=	1.87%	+ [	0.65	x (	10.40%	-	5.30%	)]	=	5.18%
11	**AVERAGE**					0.67							5.26%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

WHERE:
k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 04/03/2009 THROUGH 05/22/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE GEOMETRIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2007 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES OVER THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2008 YEARBOOK.

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f)]	=	(B) EXPECTED RETURN
1	AGL	k	=	1.87%	+ [	0.75	x (	12.30%	-	5.50%)]	=	6.97%
2	ATO	k	=	1.87%	+ [	0.60	x (	12.30%	-	5.50%)]	=	5.95%
3	LG	k	=	1.87%	+ [	0.65	x (	12.30%	-	5.50%)]	=	6.29%
4	NJR	k	=	1.87%	+ [	0.65	x (	12.30%	-	5.50%)]	=	6.29%
5	GAS	k	=	1.87%	+ [	0.75	x (	12.30%	-	5.50%)]	=	6.97%
6	NWN	k	=	1.87%	+ [	0.60	x (	12.30%	-	5.50%)]	=	5.95%
7	PNY	k	=	1.87%	+ [	0.65	x (	12.30%	-	5.50%)]	=	6.29%
8	SJI	k	=	1.87%	+ [	0.65	x (	12.30%	-	5.50%)]	=	6.29%
9	SWX	k	=	1.87%	+ [	0.70	x (	12.30%	-	5.50%)]	=	6.63%
10	WGL	k	=	1.87%	+ [	0.65	x (	12.30%	-	5.50%)]	=	6.29%
11	**AVERAGE**					0.67						6.39%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [\, ß\, (r_m - r_f)\,]$

WHERE:
k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 04/03/2009 THROUGH 05/22/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE ARITHMETIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2007 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES OVER THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2008 YEARBOOK

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.39%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.25%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.03%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.96%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.61%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.81%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.93%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	2.34%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.55%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.19%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.38%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	2.83%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	1.59%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	2.27%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.68%	3.60%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.39%	2.90%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	3.24%	2.80%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	2.85%	2.00%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.58%	1.30%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	CURRENT	0.10%	-6.10%	3.25%	0.50%	0.00% - 0.25%	0.17%	4.10%	6.01%	7.57%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 05/22/2009
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 05/22/2009
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL

UNS GAS, INC.
TEST YEAR ENDED JUNE 30, 2008
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. G-04204A-08-0571
SCHEDULE WAR - 9

LINE NO.		AGL	PCT.	ATO	PCT.	LG	PCT.	NJR	PCT.	GAS	PCT.
1	DEBT	$ 1,675.0	50.3%	$ 2,119.8	50.8%	$ 389.2	44.4%	$ 455.1	38.5%	$ 448.0	31.5%
2											
3	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.5	0.1%	0.0	0.0%	0.6	0.0%
4											
5	COMMON EQUITY	1,652.0	49.7%	2,052.5	49.2%	486.5	55.5%	727.0	61.5%	973.1	68.4%
6											
7	TOTALS	$ 3,327.0	100%	$ 4,172.3	100%	$ 876.2	100%	$ 1,182.1	100%	$ 1,421.7	100%
8											
9											
10		NWN	PCT.	PNY	PCT.	SJI	PCT.	SWX	PCT.	WGL	PCT.
11											
12	DEBT	$ 512.0	44.9%	$ 794.3	47.2%	$ 332.8	39.2%	$ 1,185.5	51.0%	$ 603.7	38.5%
13											
14	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	100.0	4.3%	28.2	1.8%
15											
16	COMMON EQUITY	628.4	55.1%	887.2	52.8%	515.3	60.8%	1,037.8	44.7%	935.1	59.7%
17											
18	TOTALS	$ 1,140.4	100%	$ 1,681.5	100%	$ 848.1	100%	$ 2,323.3	100%	$1,567.0	100%
19											
20											
21		NATURAL GAS LDC									
22		AVERAGE	PCT.								
23											
24	DEBT	$ 851.5	45.9%								
25											
26	PREFERRED STOCK	12.9	0.7%								
27											
28	COMMON EQUITY	989.5	53.4%								
29											
30	TOTALS	$ 1,854.0	100%								

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS

EXHIBIT
R-14
ADMITTED

UNS GAS, INC.

DOCKET NO. G-04204A-08-0571

SURREBUTTAL TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 29, 2009

TABLE OF CONTENTS

INTRODUCTION

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

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

Q. Please state the purpose of your surrebuttal testimony.

A. The purpose of my surrebuttal testimony is to respond to UNSG's rebuttal testimony on RUCO's recommended rate of return on invested capital (which includes RUCO's recommended cost of debt and cost of common equity) for the Company's natural gas distribution operations located in northern Arizona and Santa Cruz County.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes. On June 8, 2009, I filed direct testimony with the ACC. My direct testimony addressed the cost of capital issues that were raised in UNSG's Application that was filed on November 7, 2008.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains four parts: the introduction that I have just presented; a summary of UNSG's rebuttal testimony; a comparison of the cost of capital recommendations being made by the parties to the case; and a section on the cost of equity capital.

Q. Will you address the FVROR issues associated with the case?

A. No. RUCO consultant Ralph Smith will discuss the FVROR aspects of the case.

SUMMARY OF UNSG GAS, INC.'S REBUTTAL TESTIMONY

Q. Have you reviewed UNSG'S rebuttal testimony?

A. Yes. I have reviewed the rebuttal testimonies of Company witnesses David G. Hutchens and Kentton C. Grant, which were filed on July 8, 2009.

Q. Please summarize Mr. Hutchens's rebuttal testimony.

A. Mr. Hutchens' rebuttal testimony addresses all of the points of disagreement that the Company has with ACC Staff and RUCO. In regard to cost of capital, Mr. Hutchens expresses his displeasure with the FVROR recommendations of ACC Staff and RUCO.

Q. Please summarize Mr. Grant's rebuttal testimony.

A. Mr. Grant's rebuttal testimony expresses his belief that the cost of equity recommendation presented in my direct testimony is too low and criticizes my decision to average the results of my single stage DCF model with the results of my CAPM models (which used both an arithmetic and geometric mean to arrive at the market risk premium component).

COMPARISON OF RECOMMENDATIONS

Q. Are the parties to the case in agreement on the issue of capital structure?

A. Yes, the parties to the case are in agreement on the issue of capital structure. Both ACC Staff and RUCO are recommending that the Commission adopt the Company-proposed capital structure comprised of 50.01 percent long-term debt and 49.99 percent common equity.

Q. Are ACC Staff and RUCO also in agreement with the Company-proposed 6.49 percent cost of long-term debt?

A. Yes. ACC Staff witness David C. Parcell and I have recommended that the Commission adopt the Company-proposed 6.49 percent cost of long-term debt.

Q. Are UNSG, ACC Staff and RUCO in agreement on a cost of equity capital for the Company?

A. No. As is typical in utility rate cases there is substantial disagreement on a cost of common equity.

Q. Please summarize the costs of common equity and the OCROR's that are being recommended by the parties to the case.

A. In regard to the cost of common equity, the parties to the case are presently recommending the following estimates:

UNSG	11.00%
ACC Staff	10.00%
RUCO	8.61%

As can be seen in the above comparison, the Company-proposed cost of equity capital is 239 basis points higher than my recommended cost of equity capital. The difference between my recommended cost of equity and Mr. Parcell's recommended cost of equity is 139 basis points. The OCROR (i.e. the weighted cost of capital based on the costs of debt and equity noted above) being recommended by the parties to the case are as follows:

UNSG	8.75%
ACC Staff	8.24%
RUCO	7.55%

As can be seen above, there is presently a 120 basis point difference between the Company-proposed 8.75 percent OCROR (before any FVROR adjustment) and RUCO's recommended weighted cost of capital of 7.55 percent. RUCO and ACC Staff's recommended OCROR are within 69 basis points of each other.

Q. What FVROR's are the parties to the case recommending?

A. The parties to the case are recommending the following FVROR's:

UNSG	6.80%
ACC Staff	6.03%
RUCO	5.38%

The above comparison shows a difference of 142 basis points between the Company and RUCO's recommended FVROR's and a difference of 65 basis points between the ACC Staff and RUCO recommendations.

COST OF EQUITY CAPITAL

Q. Has there been any recent activity in regard to interest rates?

A. Yes. On June 24, 2009, after a two-day meeting, the Federal Reserve chose not to enlarge its program to buy Treasury bonds to spur growth and stated again that its key Federal Funds interest rate will remain near zero "for an extended period." The Fed also announced that it will proceed with its previously announced plans to buy up to $300 billion in long-term U.S. Treasury bonds by autumn and up to $1.25 trillion in mortgage-backed securities by year's end. The Fed further stated that it would "continue to evaluate the timing and overall amounts" of the purchases of the aforementioned financial instruments.[1]

...

[1] Reddy, Sudeep and Geoffrey T. Smith, "Fed on Holds as Slump Eases" The Wall Street Journal, June 25, 2009

Q. Has Value Line published an update on the natural gas utility industry since you filed your direct testimony?

A. Yes. Value Line published its quarterly update on the natural gas utility industry on June 12, 2009.

Q. Have you updated your recommended cost of common equity based on more recent information on interest rates and the latest Value Line data on the natural gas utility industry?

A. Yes. Based on updated information I have obtained a cost of equity estimate that is approximately 30 basis points lower than the 8.61 percent cost of equity that I recommended in my direct testimony filed on June 12, 2009.

Q. Are you revising your recommended cost of equity capital based on your updated results?

A. No. I believe that my original 8.61 percent estimate is still reasonable given the current state of interest rates and the current state of the economy.

...

Q. Please address Mr. Grant's criticism that the 5-year Treasury rate that you used as the risk free rate of return in your CAPM models is not reflective of the "investment period" used by investors to value common stocks.

A. Mr. Grant has expressed the broad assumption that the "relevant" period that the investment community relies on to value common stocks is "a very long period." But the fact is that utilities typically file for rates within a three to five-year period and the investment community is aware of that fact and understands the effect of rate case proceedings on earnings. Information on rate case proceedings is available to investors through SEC filings, investment research firms such as Value Line, and the mainstream financial press. One only has to look at UNSG as proof of this. The Company's prior rates were established on November 8, 2007 and UNSG filed for new rates almost one year later to the day for new rates. Any investor who follows the Company's publicly traded parent would be aware of the impact that the Company's actions would have on future earnings and would base his or her investment decisions based on that information.

Q. Can you cite another reason why you believe the 5-year treasury instrument used in your CAPM analysis is appropriate?

A. Yes. Professional analysts at investment services such as Value Line and Zacks Investment Research typically do not make projections beyond five years. In fact, the Federal Energy Regulatory Commission ("FERC") places more emphasis on short-term projections (i.e. one to five years) in the multi-stage DCF model that Mr. Grant used to arrive at his 11.00 percent cost of equity recommendation.

Q. Please explain how the FERC places more emphasis on short-term projections in the multi-stage DCF model.

A. The multi-stage DCF model required by the FERC weighs short-term estimates of growth, similar to the one to five-year projections that I relied on to develop the "g" component in my single stage DCF model, by a factor of two-thirds. The FERC's rationale is that short-term estimates of growth are more predictable and deserve more weight than long-term estimates such as the equally-weighted long-term estimates of growth used in the multi-stage DCF model that Mr. Grant has relied on. This is explained in the following excerpt from the FERC's Cost-of-Service Rates Manual (Attachment A):

> "**Return on Equity or Cost of Equity:** This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow (DCF) analysis of a proxy group of publicly held natural gas companies. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short-term growth estimates and the other long-term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long-term growth rate projections. An equity

> return is then selected within this zone based on an analysis of the company's risk."

Q. Please explain why Mr. Grant's criticism regarding the use of a geometric mean in a CAPM analysis is unfounded.

A. The information on both the geometric and arithmetic means, published by Morningstar, is widely available to the investment community. For this reason alone I believe that the use of both means in a CAPM analysis is appropriate.

The best argument in favor of the geometric mean is that it provides a truer picture of the effects of compounding on the value of an investment when return variability exists. This is particularly relevant in the case of the return on the stock market, which has had its share of ups and downs over the 1926 to 2007 observation period used in my CAPM analysis.

Q. Can you provide an example to illustrate the difference between arithmetic and geometric means?

A. Yes. The following example may help. Suppose you invest $100 and realize a 20.0 percent return over the course of a year. So at the end of year 1, your original $100 investment is now worth $120. Now let's say that over the course of a second year you are not as fortunate and the value of your investment falls by 20.0 percent. As a result of this, the $120 value of your original $100 investment falls to $96. An arithmetic mean of the return on your investment over the two-year period is zero percent calculated as follows:

$$(\text{year 1 return} + \text{year 2 return}) \div \text{number of periods} =$$

$$(20.0\% + -20.0\%) \div 2 =$$

$$(0.0\%) \div 2 = \underline{\underline{0.0\%}}$$

The arithmetic mean calculated above would lead you to believe that you didn't gain or lose anything over the two-year investment period and that your original $100 investment is still worth $100. But in reality, your original $100 investment is only worth $96. A geometric mean on the other hand calculates a compound return of negative 2.02 percent as follows:

$$(\text{year 2 value} \div \text{original value})^{1/\text{number of periods}} - 1 =$$

$$(\$96 \div \$100)^{1/2} - 1 =$$

$$(0.96)^{1/2} - 1 =$$

$$(0.9798) - 1 =$$

$$-0.0202 = \underline{\underline{-2.02\%}}$$

The geometric mean calculation illustrated above provides a truer picture of what happened to your original $100 over the two-year investment period.

As can be seen in the preceding example, in a situation where return variability exists, a geometric mean will always be lower than an arithmetic mean, which probably explains why utility consultants typically put up a strenuous argument against the use of a geometric mean.

Q. Can you cite any other evidence that supports your use of both a geometric and an arithmetic mean?

A. Yes. In the third edition of their book, Valuation: Measuring and Managing the Value of Companies, authors Tom Copeland, Tim Koller and Jack Murrin ("CKM") make the point that, while the arithmetic mean has been regarded as being more forward looking in determining market risk premiums, a true market risk premium may lie somewhere between the arithmetic and geometric averages published in Morningstar's SBBI yearbook.

Q. Please explain.

A. In order to believe that the results produced by the arithmetic mean are appropriate, you have to believe that each return possibility included in the calculation is an independent draw. However, research conducted by CKM demonstrates that year-to-year returns are not independent and are actually auto correlated (i.e. a relationship that exists between two or more returns, such that when one return changes, the other, or others, also change), meaning that the arithmetic mean has less credence. CKM also explains two other factors that would make the Morningstar arithmetic mean too high. The first factor deals with the holding period. The arithmetic mean depends on the length of the holding period and there is no "law" that says that holding periods of one year are the "correct" measure. When longer periods (e.g. 2 years, 3 years etc.) are observed, the arithmetic mean drops about 100 basis points. The second factor deals with a situation known as survivor bias. According to CKM, this is a well-documented problem with the Morningstar historical return series in that it only measures the returns of successful firms, that is, those firms that are listed on stock exchanges. The Morningstar historical return series does not measure the failures, of which there are many. Therefore, the return expectations in the future are likely to be lower than the Morningstar historical averages. After conducting their analysis, CKM concluded that 4.00 percent to 5.50 percent is a reasonable forward looking market risk premium. Adding the current 5-year Treasury yield of 2.23 percent to these two estimates indicates a cost of equity range of 6.23 percent to 7.73 percent. Taking into consideration the fact that utilities generally exhibit less risk than industrials, a return in the low end of this range would be reasonable. In fact, my 8.61 percent cost of common equity estimate is 88 basis points more than the high end of the range exhibited above.

Q. Has the Commission authorized rates of return that were derived through the use of both arithmetic and geometric means in prior decisions?

A. Yes.

Q. Can you provide further support for the reasonableness of the market risk premiums used in your CAPM models?

A. Yes. In his direct testimony in a prior Arizona Public Service Company ("APS") rate case proceeding, RUCO consultant Stephen G. Hill makes the argument for market risk premiums ranging from 4.0 percent to 6.0 percent[2] (Attachment B). On page 46 of his APS testimony, Mr. Hill supports his argument for lower market risk premiums by citing two scholarly articles on the subject published by noted academics. In the first paper titled *The Equity Premium*, published in 2002, Eugene Fama and Kenneth French take the position that Ibbotson Associates' historical market risk premiums (now published by Morningstar) have overstated investor expectations.

Q. Can you cite any other sources that support Mr. Hill's views, in his APS rate case testimony, that 4.0 percent to 6.0 percent is a reasonable market risk premium on a forward-looking basis?

A. Yes. During the 39th annual Financial Forum of the Society of Utility and Regulatory Financial Analysts, which was held at Georgetown University

[2] Lines 25 through 29 of page 45, and lines 1 through 4 of page 46 of the direct testimony of RUCO consultant Stephen G. Hill, Docket No. E-01345A-05-0816 et al.

in Washington D.C. on April 19 and 20, 2007, I had the opportunity to hear the views of Aswath Damodaran, Ph. D. and Felicia C. Marston, Ph. D., professors of finance from New York University and the University of Virginia respectively, who have conducted empirical research on this subject. Dr. Damodaran and Dr. Marston advocated 4.0 to 5.5 percent estimates during a panel discussion that provided both professors with the opportunity to explain their research on the equity risk premium and to answer questions from other financial analysts in attendance. Each of the panelists stated that they believed that a reasonable market risk premium fell between 4.0 percent and 5.0 percent when asked to provide estimates based on their research.

Q. What would your CAPM results be if the market risk premiums of 4.0 percent to 6.0 percent, advocated by Mr. Hill, were used in your CAPM model?

A. Using an updated 2.23 percent yield on a 5-year Treasury instrument (r_f), an updated beta of 0.67 (published in the recent Value Line natural gas utility industry update), and the market risk premiums (r_m - r_f) of 4.0 percent to 6.0 percent, advocated by Mr. Hill, in my CAPM model produces the following results:

Using a 4.0% Market Risk Premium

$$k = r_f + [\, ß\,(r_m - r_f)\,]$$

$$k = 2.23\% + [\, 0.67\,(4.0\%)\,]$$

$$k = 2.23\% + 2.68\%$$

$$k = \underline{\underline{4.91\%}}$$

Using a 6.0% Market Risk Premium

$$k = r_f + [\, ß\,(r_m - r_f)\,]$$

$$k = 2.23\% + [\, 0.67\,(6.0\%)\,]$$

$$k = 2.23\% + 4.02\%$$

$$k = \underline{\underline{6.25\%}}$$

These results are lower than the 5.26 percent and 6.39 percent estimates that I used to calculate my recommended 8.61 percent cost of common equity. When the market risk premium information noted above is taken into consideration, it is clear that Mr. Grant's market risk premium inputs, as opposed to mine, appear to be out of line.

Q. Do you have any data that supports a 4.00 percent equity risk premium during the market crises which unfolded in September of 2008?

A. Yes. In September 2008 Dr. Damodaran, who I noted earlier in my testimony, presented a paper titled <u>Equity Risk Premium (ERP): Determinants, Estimation and Implications</u>, which contained an October update that presented data on the swings in implied equity risk premium that occurred between September 12, 2008 and October 16, 2008. During that time frame, implied equity risk premiums ranged from 4.20 percent to 6.39 percent. The 5.30 percent mean average of that range is 65 basis points lower than the 5.95 percent average of my market risk premium using both geometric and arithmetic means.

Q. Please respond to Mr. Grant's statement that he is "shocked" that you would give weight to the low numbers produced by your CAPM analysis.

A. I see no reason to be shocked when one considers the current state of lower interest rates on low risk investments such as U.S. Treasury instruments and various bank certificates of deposit (Attachment C). The results of my CAPM analyses (using both arithmetic and geometric means) are simply reflecting this situation. From the perspective that public utilities have traditionally been viewed as safe investments, all things being equal it is not reasonable to believe that their costs of equity capital should be in the 11.00 percent level advocated by Mr. Grant.

Q. Please address Mr. Grant's argument that common shareholders bear a higher risk than bond holders and expect a higher return than the yields of utility debt instruments.

A. I do not disagree with Mr. Grant on this point. The question is how much more of a risk premium is merited for a low risk regulated monopoly such as UNSG. My recommended 8.61 percent cost of common equity capital is 220 basis points higher than UNSG's 6.49 percent cost of debt. It is also 176 basis points higher than the recent 6.85 percent yield on Baa/BBB-rated utility bond and 290 basis points higher than the recent 5.71 percent yield on an A-rated utility bond. The yields of both of the aforementioned utility bonds have been in decline since I filed my direct testimony on June 12, 2009.

Q. How do the current yields on Baa/BBB and A-rated utility bonds compare to the yields displayed in Mr. Grant's rebuttal testimony Exhibit KCG-15?

A. Mr. Grant's Exhibit KCG-15 displays Baa-rated and A-rated yields of 8.00 percent and 6.50 percent respectively. However these yields were published in March of 2009. Since then they have declined by 115 and 79 basis points respectively. It would appear that utility bonds are moving in the same downward direction as the yields of other financial instruments.

Q. Has Mr. Grant made any updates to the inputs of his models that were used to derive his recommended cost of common equity?

A. No. Mr. Grant has made no attempt to revise the Company-proposed cost of equity capital by updating the inputs to his models.

Q. Does your silence on any of the issues or positions addressed in the rebuttal testimony of the Company's witnesses constitute acceptance?

A. No, it does not.

Q. Does this conclude your surrebuttal testimony on UNSG?

A. Yes, it does.

ATTACHMENT A

Cost-of-Service Rates Manual

Federal Energy Regulatory Commission
888 North Capitol Street, N.E.
Washington, D.C. 20426
United States of America
www.ferc.gov

June 1999

Table of Contents

$159,602,000, is equity financed. This means that the owners of Pipeline U.S.A. used their own funds to finance this portion of their investment.

** Pipeline U.S.A. issues its own debt which is not guaranteed by its parent, has its own bond rating and its capital structure is comparable to other equity capitalizations approved by the Commission. Therefore, Pipeline U.S.A. meets the Commission's criteria for using its own capital structure for setting its rates.*

Cost of Debt: This refers to the cost of long term debt incurred by the pipeline to construct or expand the pipeline. For ongoing pipelines that have been issuing debt, we use the actual imbedded cost of debt in the capital structure. The actual imbedded cost of debt is the weighted average of all the debt issued and the cost at which the debt was issued. For new pipelines that have indicated that they would issue debt to finance their investment, but have not yet actually issued the debt, we compute the cost of debt based on a projection, or recent historical debt cost such as historical average Baa utility bonds (Moody's Bond Survey), which is the most prevalent rating for utilities. We also use Moody's to compute the cost of debt if we decide use of a hypothetical capital structure is appropriate.

A-8, column 3, shows the cost of debt of Pipeline U.S.A. of 8.25%. The cost of debt represents a return to Pipeline U.S.A.'s bondholders. The debt return dollars appearing in Column 5 represents the cost to Pipeline U.S.A. to pay the interest on the debt to its bondholders. This debt return, or interest on debt, of $30,723,000 as shown in column (5) is included in the Return component of the cost-of-service.

Return on Equity or Cost of Equity: This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow

(DCF) analysis of a proxy group of publicly held natural gas companies. The Commission currently uses a two-stage Discounted Cash Flow (DCF) methodology. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short term growth estimates and the other long term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk. It is assumed, that most pipelines face risks that would place them in the middle of the zone of reasonableness. However, a case could be made depending on the facts of the specific pipeline that the return on equity should be outside the zone. As an example, a pipeline with a high debt capitalization ratio is usually considered more risky and thus, a higher return on equity would be expected.

We have determined that a reasonable return on equity for Pipeline U.S.A. is 14.00%. This return was at the high end of our range of equity returns because Pipeline U.S.A. is a relatively new pipeline company with a high debt capitalization ratio. The equity portion of the return permitted to be collected in rates is $22,344,000 shown in column (5) of A-8.

Pretax Return. Pretax return is the amount earned by a pipeline before income taxes and debt interest payments. Pretax return is often calculated for pipelines and used to further settlement negotiations. Using a pretax return figure can avoid the lengthy discussions and debates that surround the issues of capitalization ratios and ROE calculations and analyses. Use of a pretax return reduces these issues down to one number, a pretax percentage that can easily be compared to other pipeline's pretax returns. The pretax return figure

ATTACHMENT B

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY

OF

STEPHEN G. HILL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 18, 2006

Equation (3) states that the relevered beta equals the unlevered beta (β_U) multiplied times one plus the target debt-to-equity ratio (in this case APS's ratemaking capital structure—50% equity/50% debt), again adjusted for taxes.

Schedule 12 shows that, the average capital structure of the sample group of electric companies used to estimate the cost of equity capital in my direct testimony consists of 45.13% common equity and 54.69% fixed-income capital. That capital structure, adjusted to market levels by an average 1.69 market-to-book ratio and accounting for a 35% tax rate, produces an average value for (1-t)D/E in Equation (2) of 0.53.

Schedule 12 shows further that the measured (average Value Line) beta coefficient of the sample group of gas utility firms is 0.83, and the <u>unlevered</u> beta coefficient of those firms (i.e., what the average beta would be if those firms were financed entirely with common equity) is 0.54. When that beta is "relevered" using the methodology described above to conform to APS's ratemaking capital structure, the resulting average beta coefficient is 0.75, an decrease in beta of 0. 079 due to the sample group's lower average equity capitalization ["measured" beta of 0.83 vs. "relevered" beta of 0.751].

Finally, with the increase in beta determined, the CAPM can be used to estimate the impact of that adjustment on the cost of capital. A review of the CAPM equation (Equation (i) in Appendix D) indicates that the beta coefficient is multiplied by the market risk premium (r_m - r_f) as a step in the determination of the cost of capital. Therefore, it is possible to measure the impact of an adjustment to beta by multiplying the difference in the measured and relevered betas of the electric companies by the market risk premium.

As I noted in my discussion of the CAPM analysis in Appendix D, the long-term historical market risk premium provided by Ibbotson Associates' historical database is 5% to 6.6%. I also discuss the fact that the most recent research by Fama and French regarding the market risk premium indicates that the Ibbotson historical risk premium data overstate investor expectations, which are a return of 2.5% to 4.5% over the risk-free rate of interest.[20] Ibbotson has also published a paper recently, which indicates that investors can expect returns in the future of from 4% to 6% above the risk-free.[21] Therefore, for purposes of this analysis, I will use a range of market risk premium from 4% to 6%.

As shown in Schedule 12, an decrease in the average beta coefficient of 0.079, multiplied by a market risk premium ranging from 4% to 6%, indicates an decrease in the cost of equity capital due to reduced leverage at APS of from 32 to 48 basis points (0.079 x 4%-6% = 0.317%-0.476%).

The mid-point of the cost of common equity for the electric utility sample group, presented previously is 9.50%. Although the equity return decrement indicated is slightly higher, recognizing the decrease in financial risk due to reduced leverage at APS, a cost of equity of 9.25% for ratemaking purposes is reasonable. That represents a decrease in the cost of equity for APS (with a 50% common equity ratio) of 25 basis points below the mid-point of a reasonable range for electric utility operations, which are capitalized on average with about 45% common equity.

It is important to emphasize here that if the Commission elects to utilize the Company's requested 54.5% common equity ratio for ratesetting purposes, rather than the 50% I recommend, the equity return decrement due to lower financial risk would have to be greater than the 25 basis points I recommend. If a "target" capital common equity ratio of 54.5% were substituted in Schedule 12, the "relevered" beta would be 0.72, rather than the 0.75 used in my analysis. Also the indicated reduction in the cost of equity would range from 0.45% to 0.68%. Those data indicate that if this Commission elects to set rates for APS using its requested capital structure, an equity return decrement of 50 basis points would be reasonable.

Q. DOES THAT 9.25% EQUITY COST ESTIMATE INCLUDE AN INCREMENT FOR

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[20] Fama, E., French, K., "The Equity Premium," *The Journal of Finance*, Vol. LVII, No. 2, April 2002, pp. 637-659.

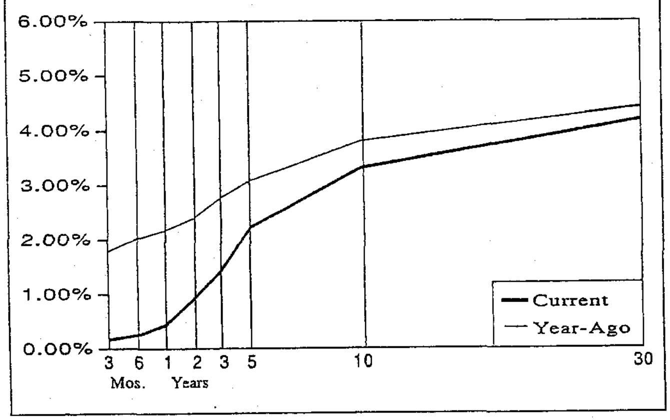
[21] Ibbotson, R, Chen, P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

ATTACHMENT C

Selected Yields

	Recent (7/08/09)	3 Months Ago (4/08/09)	Year Ago (7/09/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.36	0.33	2.62
3-month LIBOR	0.53	1.14	2.79
Bank CDs			
6-month	0.65	0.83	1.64
1-year	0.86	1.04	2.34
5-year	1.94	2.05	3.74
U.S. Treasury Securities			
3-month	0.18	0.18	1.79
6-month	0.25	0.37	2.02
1-year	0.44	0.58	2.18
5-year	2.23	1.83	3.08
10-year	3.31	2.86	3.81
10-year (inflation-protected)	1.76	1.53	1.23
30-year	4.19	3.67	4.42
30-year Zero	4.31	3.67	4.46

Treasury Security Yield Curve



	Recent (7/08/09)	3 Months Ago (4/08/09)	Year Ago (7/09/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.71	3.40	5.41
FHLMC 6.5% (Gold)	2.99	2.79	5.42
FNMA 6.5%	2.83	2.79	5.32
FNMA ARM	2.98	3.15	4.09
Corporate Bonds			
Financial (10-year) A	6.53	7.85	6.08
Industrial (25/30-year) A	5.82	6.27	6.04
Utility (25/30-year) A	5.71	6.20	6.25
Utility (25/30-year) Baa/BBB	6.85	7.63	6.35
Foreign Bonds (10-Year)			
Canada	3.28	2.90	3.69
Germany	3.28	3.21	4.41
Japan	1.30	1.46	1.62
United Kingdom	3.62	3.35	4.89
Preferred Stocks			
Utility A	7.59	6.35	6.27
Financial A	6.57	7.80	7.75
Financial Adjustable A	5.48	5.48	5.48
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.83	4.95	4.83
25-Bond Index (Revs)	5.75	5.75	5.25
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.47	1.78
1-year A	0.93	1.20	1.80
5-year Aaa	1.96	2.03	3.33
5-year A	2.40	3.45	3.43
10-year Aaa	3.09	3.20	3.90
10-year A	3.45	4.75	4.10
25/30-year Aaa	4.59	4.77	4.74
25/30-year A	5.05	6.25	4.84
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.55	6.30	5.03
Electric AA	5.65	6.40	5.05
Housing AA	5.80	6.70	5.10
Hospital AA	5.90	6.65	5.15
Toll Road Aaa	5.60	6.45	5.05

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	7/1/09	6/17/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	687739	791810	-104071	805680	768030	503132
Borrowed Reserves	404097	458240	-54143	512001	551755	480824
Net Free/Borrowed Reserves	283642	333570	-49928	293678	216275	22308

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

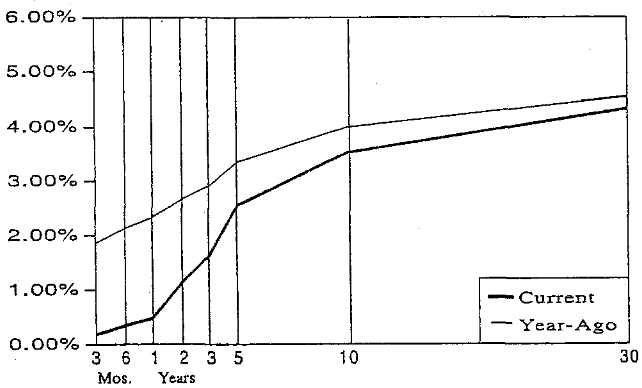
	Recent Levels			Growth Rates Over the Last...		
	6/22/09	6/15/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1668.5	1656.0	12.5	33.3%	9.1%	20.7%
M2 (M1+savings+small time deposits)	8369.2	8368.9	0.3	1.4%	5.7%	9.3%

Selected Yields

	Recent (6/30/09)	3 Months Ago (4/01/09)	Year Ago (7/01/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.41	0.44	2.65
3-month LIBOR	0.60	1.18	2.79
Bank CDs			
6-month	0.65	0.83	1.75
1-year	0.86	1.04	2.43
5-year	1.92	2.06	3.75
U.S. Treasury Securities			
3-month	0.18	0.20	1.86
6-month	0.34	0.39	2.12
1-year	0.48	0.54	2.33
5-year	2.56	1.64	3.35
10-year	3.53	2.65	4.00
10-year (inflation-protected)	1.80	1.32	1.35
30-year	4.33	3.50	4.55
30-year Zero	4.41	3.52	4.57

	Recent (6/30/09)	3 Months Ago (4/01/09)	Year Ago (7/01/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.77	3.53	5.60
FHLMC 6.5% (Gold)	3.23	3.12	5.59
FNMA 6.5%	3.07	3.04	5.51
FNMA ARM	2.53	3.15	4.09
Corporate Bonds			
Financial (10-year) A	6.87	7.49	6.37
Industrial (25/30-year) A	5.96	6.17	6.16
Utility (25/30-year) A	5.79	5.99	6.24
Utility (25/30-year) Baa/BBB	6.88	7.41	6.43
Foreign Bonds (10-Year)			
Canada	3.36	2.78	3.74
Germany	3.39	2.99	4.61
Japan	1.36	1.35	1.68
United Kingdom	3.69	3.13	5.15
Preferred Stocks			
Utility A	6.10	6.74	6.25
Financial A	7.75	9.90	7.28
Financial Adjustable A	5.48	5.48	5.48
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.79	5.00	4.83
25-Bond Index (Revs)	5.77	5.78	5.25
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.50	1.78
1-year A	1.10	0.60	1.80
5-year Aaa	2.07	2.08	3.33
5-year A	3.47	2.33	3.43
10-year Aaa	3.23	3.20	3.90
10-year A	4.75	3.73	4.10
25/30-year Aaa	4.66	4.79	4.74
25/30-year A	6.18	5.83	4.84
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.05	5.80	5.03
Electric AA	6.10	5.85	5.05
Housing AA	6.50	6.15	5.10
Hospital AA	6.45	6.20	5.15
Toll Road Aaa	6.05	5.90	5.05

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 6/17/09	Recent Levels 6/3/09	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	791810	838497	-46687	817610	774222	477725
Borrowed Reserves	458240	497684	-39444	540680	571070	472226
Net Free/Borrowed Reserves	333570	340813	-7243	276930	203152	5499

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

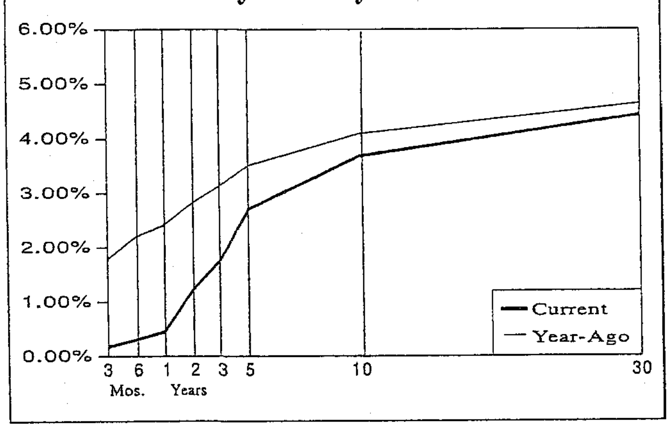
	Recent Levels 6/15/09	Recent Levels 6/8/09	Change	Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1656.9	1631.1	25.8	25.5%	7.2%	19.8%
M2 (M1+savings+small time deposits)	8369.3	8353.6	15.7	1.3%	6.4%	9.5%

Selected Yields

	Recent (6/24/09)	3 Months Ago (3/25/09)	Year Ago (6/25/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.44	0.51	2.80
3-month LIBOR	0.60	1.23	2.81
Bank CDs			
6-month	0.65	0.83	1.75
1-year	0.87	1.04	2.41
5-year	1.92	2.06	3.75
U.S. Treasury Securities			
3-month	0.18	0.18	1.79
6-month	0.31	0.40	2.20
1-year	0.46	0.58	2.42
5-year	2.71	1.81	3.52
10-year	3.69	2.78	4.10
10-year (inflation-protected)	1.88	1.38	1.51
30-year	4.43	3.74	4.64
30-year Zero	4.50	3.77	4.66

	Recent (6/24/09)	3 Months Ago (3/25/09)	Year Ago (6/25/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.79	3.48	5.68
FHLMC 6.5% (Gold)	3.28	2.99	5.64
FNMA 6.5%	3.06	3.00	5.55
FNMA ARM	2.53	3.60	4.30
Corporate Bonds			
Financial (10-year) A	6.75	7.51	6.22
Industrial (25/30-year) A	6.07	6.48	6.19
Utility (25/30-year) A	5.89	6.28	6.25
Utility (25/30-year) Baa/BBB	7.30	7.71	6.48
Foreign Bonds (10-Year)			
Canada	3.45	2.96	3.71
Germany	3.42	3.15	4.61
Japan	1.39	1.29	1.69
United Kingdom	3.70	3.28	5.12
Preferred Stocks			
Utility A	6.05	6.11	6.21
Financial A	8.21	9.42	7.20
Financial Adjustable A	5.47	5.47	5.47

Treasury Security Yield Curve



	Recent (6/24/09)	3 Months Ago (3/25/09)	Year Ago (6/25/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.86	4.98	4.76
25-Bond Index (Revs)	5.78	5.81	5.20
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.50	1.70
1-year A	0.90	0.60	1.80
5-year Aaa	2.17	2.15	3.40
5-year A	2.60	2.45	3.50
10-year Aaa	3.27	3.24	4.00
10-year A	3.63	3.74	4.20
25/30-year Aaa	4.70	4.85	4.88
25/30-year A	5.15	5.85	5.08
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.80	5.90	5.10
Electric AA	5.90	6.00	5.15
Housing AA	6.10	6.30	5.30
Hospital AA	6.05	6.25	5.40
Toll Road Aaa	5.85	6.05	5.15

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	6/17/09	6/3/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	791801	838494	-46693	817609	774221	477725
Borrowed Reserves	458240	497684	-39444	540680	571070	472226
Net Free/Borrowed Reserves	333561	340810	-7249	276928	203151	5499

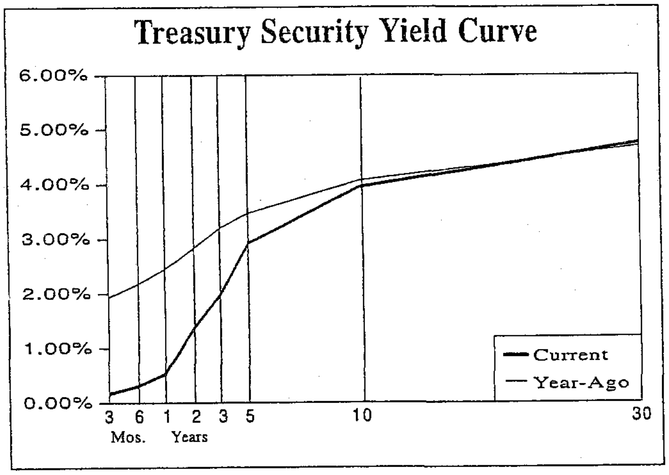
MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	6/8/09	6/1/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1631.1	1596.8	34.3	14.4%	6.9%	17.6%
M2 (M1+savings+small time deposits)	8353.8	8349.4	4.4	2.2%	7.2%	9.3%

Selected Yields

	Recent (6/10/09)	3 Months Ago (3/11/09)	Year Ago (6/11/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.34	0.75	2.53
3-month LIBOR	0.64	1.33	2.79
Bank CDs			
6-month	0.66	0.84	1.76
1-year	0.87	1.05	2.25
5-year	1.92	2.07	3.37
U.S. Treasury Securities			
3-month	0.17	0.22	1.94
6-month	0.31	0.45	2.17
1-year	0.53	0.70	2.45
5-year	2.92	1.94	3.47
10-year	3.95	2.91	4.07
10-year (inflation-protected)	1.86	2.01	1.47
30-year	4.76	3.66	4.69
30-year Zero	4.84	3.56	4.74
Mortgage-Backed Securities			
GNMA 6.5%	4.26	4.21	5.69
FHLMC 6.5% (Gold)	3.07	3.58	5.68
FNMA 6.5%	2.91	3.73	5.58
FNMA ARM	2.53	3.60	4.30
Corporate Bonds			
Financial (10-year) A	6.82	7.38	5.86
Industrial (25/30-year) A	6.50	6.18	6.25
Utility (25/30-year) A	6.28	6.05	6.23
Utility (25/30-year) Baa/BBB	7.76	7.50	6.50
Foreign Bonds (10-Year)			
Canada	3.64	2.92	3.81
Germany	3.69	3.07	4.55
Japan	1.55	1.32	1.85
United Kingdom	3.92	3.09	5.13
Preferred Stocks			
Utility A	7.62	6.96	6.33
Financial A	8.63	11.44	6.76
Financial Adjustable A	5.46	5.46	5.46
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.71	4.96	4.59
25-Bond Index (Revs)	5.63	5.80	5.04
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.57	1.74
1-year A	0.90	0.67	1.84
5-year Aaa	2.14	2.30	3.07
5-year A	2.57	2.55	3.17
10-year Aaa	3.21	3.30	3.74
10-year A	3.57	3.83	3.94
25/30-year Aaa	4.72	4.87	4.56
25/30-year A	5.16	5.91	4.76
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.85	5.90	4.85
Electric AA	5.95	5.95	4.90
Housing AA	6.25	6.25	5.05
Hospital AA	6.20	6.30	5.15
Toll Road Aaa	6.00	6.00	4.90



Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 6/3/09	5/20/09	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	838496	877071	-38575	793290	759788	448486
Borrowed Reserves	497684	554779	-57095	565243	586617	461783
Net Free/Borrowed Reserves	340812	322292	18520	228048	173171	-13297

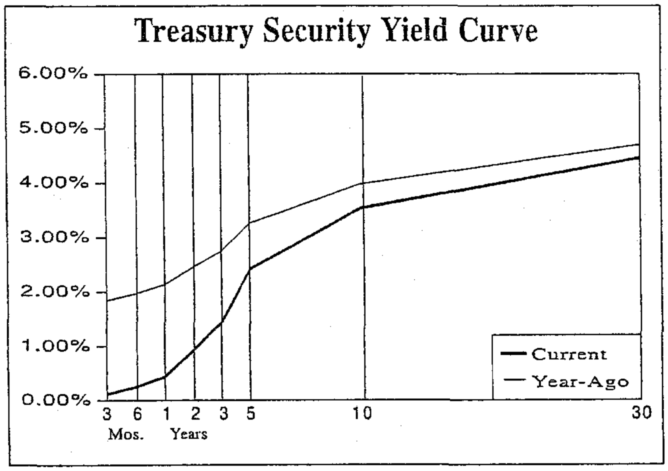
MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 5/25/09	5/18/09	Change	Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1602.2	1590.0	12.2	16.2%	10.9%	16.8%
M2 (M1+savings+small time deposits)	8358.2	8327.4	30.8	6.0%	10.1%	9.2%

Selected Yields

	Recent (6/3/09)	3 Months Ago (3/04/09)	Year Ago (6/04/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.28	0.79	2.47
3-month LIBOR	0.64	1.28	2.67
Bank CDs			
6-month	0.70	0.84	1.76
1-year	0.92	1.04	2.25
5-year	1.92	2.07	3.37
U.S. Treasury Securities			
3-month	0.12	0.25	1.84
6-month	0.25	0.43	1.97
1-year	0.44	0.66	2.13
5-year	2.42	1.94	3.26
10-year	3.54	2.97	3.98
10-year (inflation-protected)	1.63	2.03	1.44
30-year	4.45	3.67	4.70
30-year Zero	4.53	3.55	4.79

	Recent (6/3/09)	3 Months Ago (3/04/09)	Year Ago (6/04/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.37	4.19	5.49
FHLMC 6.5% (Gold)	2.89	4.13	5.46
FNMA 6.5%	2.78	4.15	5.36
FNMA ARM	2.53	3.60	4.25
Corporate Bonds			
Financial (10-year) A	6.82	8.50	5.74
Industrial (25/30-year) A	6.35	6.23	6.22
Utility (25/30-year) A	6.17	5.93	6.23
Utility (25/30-year) Baa/BBB	7.83	7.16	6.50
Foreign Bonds (10-Year)			
Canada	3.36	3.02	3.64
Germany	3.57	3.14	4.38
Japan	1.55	1.31	1.78
United Kingdom	3.79	3.64	4.95
Preferred Stocks			
Utility A	6.10	7.62	6.29
Financial A	8.35	12.59	6.75
Financial Adjustable A	5.53	5.53	5.53



	Recent (6/3/09)	3 Months Ago (3/04/09)	Year Ago (6/04/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.61	4.87	4.52
25-Bond Index (Revs)	5.53	5.76	4.99
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.57	1.77
1-year A	1.13	0.67	1.87
5-year Aaa	2.02	2.30	2.94
5-year A	3.45	2.90	3.04
10-year Aaa	3.01	3.29	3.58
10-year A	4.55	3.79	3.78
25/30-year Aaa	4.64	4.86	4.47
25/30-year A	6.16	5.86	4.67
Revenue Bonds (Revs) (25/30-Year)			
Education AA	6.20	5.90	4.75
Electric AA	6.25	6.00	4.80
Housing AA	6.55	6.25	4.95
Hospital AA	6.50	6.20	5.05
Toll Road Aaa	6.30	6.05	4.80

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/20/09	5/6/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	877072	777457	99615	769710	743091	417505
Borrowed Reserves	554779	507911	46868	578275	602866	449070
Net Free/Borrowed Reserves	322293	269546	52747	191435	140225	-31565

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	5/18/09	5/11/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1590.2	1596.0	-5.8	8.0%	10.2%	16.4%
M2 (M1+savings+small time deposits)	8327.5	8315.3	12.2	4.0%	10.2%	9.1%

ATTACHMENT D

Equity Risk Premiums (ERP): Determinants, Estimation and Implications

September 2008

(with an October update reflecting the market crisis)

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Equity Risk Premiums (ERP): Determinants, Estimation and Implications

Equity risk premiums are a central component of every risk and return model in finance and are a key input into estimating costs of equity and capital in both corporate finance and valuation. Given their importance, it is surprising how haphazard the estimation of equity risk premiums remains in practice. In the standard approach to estimating equity risk premiums, historical returns are used, with the difference in annual returns on stocks versus bonds over a long time period comprising the expected risk premium. We note the limitations of this approach, even in markets like the United States, which have long periods of historical data available, and its complete failure in emerging markets, where the historical data tends to be limited and volatile. We look at two other approaches to estimating equity risk premiums – the survey approach, where investors and managers ar asked to assess the risk premium and the implied approach, where a forward-looking estimate of the premium is estimated using either current equity prices or risk premiums in non-equity markets. We close the paper by examining why different approaches yield different values for the equity risk premium, and how to choose the "right" number to use in analysis. (In an addendum, we also look at equity risk premiums during the market crisis, starting on September 12, 2008 through October 16, 2008.)

This regression reinforces the view that equity risk premiums should not be constants but should be linked to the level of interest rates, at the minimum, and perhaps even to the slope of the yield curve. In Septermber 2008, for instance, when the 10-year treasury bond rate was 3.55% and the 6-month treasury bill rate was at 2.4%, the implied equity risk premium would have been computed as follows:

Implied ERP = 1.93% + 0.371 (3.55%) - .111 (3.55% – 2.4%) = 3.12%

This would have been well below the observed implied equity risk premium of about 4.54% and the average implied equity risk premium of 4% between 1960 and 2008.

While we have considered only interest rates in this analysis, it can be expanded to include other fundamental variables including measures of overall economic growth (such as expected growth in the GDP), exchange rates and even measures of risk aversion.

Implied Equity Risk Premiums during a Market Crisis – 9/15/08 to 10/16/08

When we use historical risk premiums, we are, in effect, assuming that equity risk premiums do not change much over short periods and revert back over time to historical averages. This assumption was viewed as reasonable for mature equity markets like the United States, but was put under a severe test during the market crisis that unfolded with the fall of Lehman Brothers on September 15, and the subsequent collapse of equity markets, first in the US, and then globally.

Since implied equity risk premiums reflect the current level of the index, the 22 trading days between September 15, 2008, and October 16, 2008, offer us an unprecedented opportunity to observe how much the price charged for risk can change over short periods. In figure 7A, we depict the S&P 500 on one axis and the implied equity risk premium on the other. To estimate the latter, we used the level of the index and the treasury bond rate at the end of each day and used the total dollar dividends and buybacks over the trailing 12 months to compute the total yield. For example, the total dollar dividends and buybacks on the index for the trailing 12 months of 52.58 resulted in a dividend yield of 4.20% on September 12 (when the index closed at 1252) but jumped to 4.97% on October 6, when the index closed at 1057.[71]

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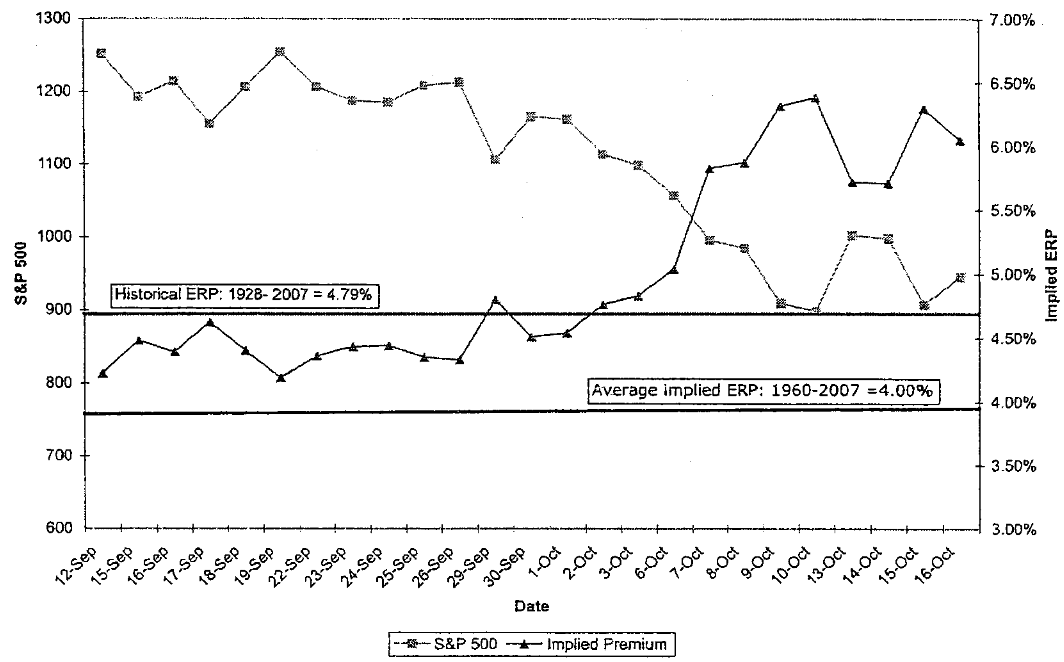
[71] It is possible, and maybe even likely, that the banking crisis and resulting economic slowdown was leading some companies to reassess policies on buybacks. Alcoa, for instance, announced that it was terminating stock buybacks. However, other companies stepped up buybacks in response to lower stock prices. If the total cash return was dropping, as the market was, the implied equity risk premiums should be lower than the numbers that we have computed.

Figure 7A: Implied Equity Risk Premium - 9/12- 10/16



In a period of a month, the implied equity risk premium rose from 4.20% on September 12 to 6.39% at the close of trading of October 10. Even more disconcertingly, there were wide swings in the equity risk premium within a day; in the last trading hour just on October 10, the implied equity risk premium ranged from a high of 6.6% to a low of 6.1%.

There are two ways in which we can view this volatility. One the one side, proponents of using historical averages (either of actual or implied premiums) will use the day-to-day volatility in market risk premiums to argue for the stability of historical averages. They are implicitly assuming that when the crisis passes, markets will return to the status quo. On the other hand, there will be many who point to the unprecedented jump in implied premiums over a four-week period and note the danger of sticking with a "fixed" premium. They will argue that there are sometimes structural shifts in markets, i.e. big events that change market risk premiums for long periods, and that we should be therefore modifying the risk premiums that we use in valuation as the market changes around us.

There is one final point to be made about the changes in risk premiums during this crisis. The volatility captured in figure 7A was not restricted to just the US equity markets. Global equity markets gyrated with and sometimes more than the US, default spreads widened considerably in corporate bond markets, commercial paper and LIBOR rates soared while the 3-month treasury bill rate dropped close to zero and the implied volatility in option markets rose to levels never seen before. Gold surged but other commodities, such as oil and grains, dropped. Not only did we discover how intertwined equity markets are around the globe but also how markets for all risky assets are tied together. We will explicitly consider these linkages as we go through the rest of the paper.

Extensions of Implied Equity Risk Premium

The practice of backing out risk premiums from current prices and expected cashflows is a flexible one. It can be expanded into emerging markets to provide estimates of risk premiums that can replace the country risk premiums we developed in the last section. Within an equity market, it can be used to compute implied equity risk premiums for individual sectors or even classes of companies.

a. Other Equity Markets

The advantage of the implied premium approach is that it is market-driven and current, and does not require any historical data. Thus, it can be used to estimate implied equity premiums in any market, no matter how short its history, It is, however, bounded by whether the model used for the valuation is the right one and the availability and reliability of the inputs to that model. Earlier in this paper, we estimated country risk premiums for Brazil, using default spreads and equity market volatile. To provide a contrast, we estimated the implied equity risk premium for the Brazilian equity market in September 2008, from the following inputs.

- The index (Bovespa) was trading at 48,345 on September 9, 2008, and the dividend yield on the index over the previous 12 months was approximately 2%. While stock buybacks represented negligible cash flows, we did compute the FCFE for companies in the index, and the aggregate FCFE yield across the companies was 5.41%.
- Earnings in companies in the index are expected to grow 9% (in US dollar terms) over the next 5 years, and 3.80% (set equal to the treasury bond rate) thereafter.
- The riskfree rate is the US 10-year treasury bond rate of 3.80%.

The time line of cash flows is shown below:

$$48{,}345 = \frac{2{,}853}{(1+r)} + \frac{3{,}109}{(1+r)^2} + \frac{3{,}389}{(1+r)^3} + \frac{3{,}694}{(1+r)^4} + \frac{4{,}027}{(1+r)^5} + \frac{4{,}027(1.038)}{(r-.038)(1+r)^5}$$

These inputs yield a required return on equity of 10.78%, which when compared to the treasury bond rate of 3.80% on that day results in an implied equity premium of 6.98%.

EXHIBIT
R-15
ADMITTED

Efficiency Kansas

Program Manual

Guidelines for Participants, Partner Utilities, and Partner Banks

Kansas Corporation Commission, State Energy Office
Version 1.1
July 13, 2009

www.efficiencykansas.com
785-271-3185

Table of Contents

Section 1: Efficiency Kansas Overview

1.1 Introduction

Beginning July 15, 2009, the Efficiency Kansas loan program was established by the Kansas Corporation Commission (hereafter, "KCC") to facilitate energy conservation and efficiency improvements in existing Kansas homes and small businesses. Operated by the State Energy Office, a division of the KCC, Efficiency Kansas was funded with approximately $34 million in federal economic stimulus dollars, which were authorized by the American Recovery and Reinvestment Act of 2009 (ARRA).

The Efficiency Kansas loan program is a revolving loan program. In other words, as funds are repaid, the loan fund will replenish and thus provide a long-term source of financing for cost-effective energy conservation and efficiency improvements in buildings throughout the state.

To better accomplish the program objectives (detailed below), the State Energy Office is partnering with Kansas utilities and banks to promote energy efficiency improvements in Kansas homes and small businesses. To ensure cost-effectiveness, all structures will first undergo an energy audit (see Section 2 for more details about energy audits and auditors) that results in a customized energy conservation plan. Only those improvements for which projected energy savings for the payback period exceed the project cost (see Appendix 1 for cost-effectiveness calculations) will be approved for Efficiency Kansas financing; however, customers may have the option to make upfront payments to "buy down" project costs to meet this requirement.

Future Updates

This manual may be updated or revised at any time (version number will be changed with each update). Participants, Partner Utilities, and Partner Banks should refer to the Efficiency Kansas website for the most current version.

Objectives

American Recovery and Reinvestment Act of 2009 (ARRA)

Efficiency Kansas meets the ARRA objectives of saving energy, reducing greenhouse gas emissions, creating and/or retaining jobs, and increasing energy independence. By making it easier for Kansas homeowners and businesses to make energy conservation and efficiency improvements, Efficiency Kansas will reduce the state's energy consumption and emissions of both regulated pollutants and carbon dioxide. By increasing demand for energy auditors and building contractors, Efficiency Kansas will stimulate local economies in the short-term and provide a long-term funding stream, the revolving loan fund, to ensure sustainable demand going forward.

Energy Efficiency Goals of the KCC

The new loan program is closely aligned with the KCC's overall goals for energy efficiency programs, as laid out in the final KCC order in Docket 08-GIMX-442-GIV (the "442 Docket"), in that it (1) produces cost-effective, firm energy savings, (2) requires a comprehensive approach based on sound building science principles, (3) works well with Midwest Energy's existing

How$mart® program as well as similar meter-based programs that may be offered by other utilities, and (4) allows for targeting of rental units.

Efficiency Kansas offers Kansans an affordable approach to making energy-saving improvements in buildings statewide. By using local contractors, the program will stimulate economic activity throughout the state. And by allowing the funds to recycle though the revolving loan fund, the program provides the state with a long-term source of funding for smart energy efficiency improvements to help reduce energy consumption and emissions of regulated pollutants and carbon dioxide now and in the future.

Two Tracks

Eligible Kansans (see below) will have two ways to access the Efficiency Kansas financing for energy conservation and efficiency retrofits in residential and small commercial/industrial buildings: the "utility track" and the "bank track." The *utility track* is available to Kansans whose electric and/or natural gas utility has elected to partner with Efficiency Kansas by offering a program similar to the existing How$mart® program at Midwest Energy. The bank track is available to all Kansans who wish to take out a low-interest loan directly through Partner Banks, which are located throughout the state. (See Sections 3 and 4 for more details about the utility and bank tracks, respectively.)

In some areas of the state, participants will have the option to use either the utility or the bank track to access **Efficiency Kansas** financing; in other regions, the banking option may be the only one available to eligible participants.

1.2 Eligibility Requirements

Efficiency Kansas has no income limits. All Kansas homeowners and owners of small businesses (including landlords), regardless of their income, are eligible to participate in Efficiency Kansas and may access financing for approved projects through either Partner Banks or Partner Utilities (provided their electric or natural gas utility offers a program). Tenants whose utility offers a meter-based program may also be eligible for financing.

Residential Structures

Owner-occupant

All Kansas homeowners may participate in the program, provided they meet the following criteria:

1) they are deemed creditworthy by participating utilities or banks,
2) they are Kansas residents,
3) the home is in need of energy conservation and efficiency improvements (proposed improvements must meet program guidelines), and
4) the home is located within the state of Kansas.

Rental units

Owners of property used to operate small businesses (landlords) as well as occupants/operators of small businesses (tenants) may participate in the program, provided they meet the following eligibility criteria:

1) they are deemed creditworthy by participating utilities or banks,
2) they are Kansas residents,
3) both landlord and tenant are informed of respective obligations and agree to participate,
4) the rental unit is in need of energy conservation and efficiency improvements (proposed improvements must meet program guidelines), and
5) the rental unit is located within the state of Kansas.

Mobile homes

Owner-occupants, landlords, and tenants of mobile homes may participate in program, provided the following conditions are met:

1) they are deemed creditworthy by participating utilities or banks,
2) they are Kansas residents,
3) if mobile home is a rental unit, both landlord and tenant are informed of respective obligations and agree to participate,
4) the mobile home is on a permanent foundation or basement,
5) the mobile home has had all wheels removed,
6) the mobile home is in need of energy conservation and efficiency improvements (proposed improvements must meet program guidelines),
7) the mobile home is located within the state of Kansas, and
8) the audit is performed by an energy auditor who has received Mobil Home Certification from a qualified training institution.

Small Commercial and Industrial Structures

Owner-occupant

Any Kansas small business owners may participate in the program, as long as they meet the following eligibility criteria:

1) they are deemed creditworthy by participating utilities or banks,
2) they are Kansas residents (applies to business partners),
3) the structure uses residential-sized heating and air conditioning equipment,
4) their small business or commercial structure is in need of energy conservation and efficiency improvements (proposed improvements must meet program guidelines), and
5) the small business or commercial structure is located within the state of Kansas.

Rental

Both owners of property used to operate small businesses (landlords) and occupants/operators of small businesses (tenants) may participate in the program, provided they meet the following eligibility criteria:

1) they are deemed creditworthy by participating utilities or banks,
2) they are Kansas residents,
3) both the landlord and tenant are informed of respective obligations and agree to participate,

4) the structure uses residential-sized heating and air conditioning equipment,
5) the small business or commercial structure is in need of energy conservation and efficiency improvements (proposed improvements must meet program guidelines), and
6) the small business or commercial structure is located within the state of Kansas.

1.3 Amount and Term of Financing

Participants approved for Efficiency Kansas financing will receive 100% of the approved project costs, up to the specified maximums. For both the utility and bank tracks, the maximum amount of funding for approved improvements to residential structures is $20,000 (based on experience with Midwest Energy's How$mart® program, we estimate the average residential project size will be between $5,000 and $6,000). For small commercial and industrial structures, the maximum amount of funding for approved projects is $30,000, regardless of whether the financing is obtained through Partner Banks or Partner Utilities.

The maximum term of all financed energy efficiency projects is 15 years, regardless of customer type or track followed to access Efficiency Kansas.

Section 2: Energy Auditors and Energy Audits

2.1 Auditor Requirements and Responsibilities

Auditor Training

All projects that are approved for Efficiency Kansas financing must be based on energy audits that have been performed by Efficiency Kansas "qualified" auditors. "Qualified auditors" are those who have met the criteria established by the State Energy Office and have requested that they be included in the listing of qualified auditors. This list will be maintained by the State Energy Office and be available on the Efficiency Kansas web site. All energy auditors on the Efficiency Kansas qualified auditor list will have undergone training and been certified by one of the qualified training institutions listed below.

Kansas Building Science Institute
200 Zeandale Road, PO Box 1264, Manhattan, KS 66505-1264 (877-537-2425)
Two training courses at the Kansas Building Science Institute are approved: (1) Weatherization Inspection Training and (2) HERS (Home Energy Rating System) training, combined with an additional two-day Combustion Analysis training.

Metropolitan Energy Center
3808 Paseo, Kansas City, MO 64109 (877-620-1803)
The Energy and Environmental Training Center (EETC) of Metropolitan Energy Center offers the EETC Energy Auditor Certification.

Neosho County Community College
800 West 14th Street, Chanute, KS 66720-2639 (620-431-2820)
Neosho County Community College offers three types of training: (1) Fast-Track Energy Auditor Certificate, (2) Semester Energy Auditor Certificate, and (3) Certificate in Energy Management.

All auditors will be asked to indicate their service area, and the State Energy Office will include this information in the online list of qualified auditors.

Auditors performing audits on mobile homes must be certified by receiving mobile home audit training at a qualified institution.

Liability insurance

Qualified auditors are not required to hold liability insurance; however, the Efficiency Kansas qualified auditor list will identify as bonded those auditors that show proof of liability insurance.

Software

Computer modeling is required for a qualified energy audit. Auditors will be required to use either REM/Rate or REM/Design audit software.

2.2 Energy Audit Specifications

The following section details the minimum requirements for an energy audit. Auditors should review this section to ensure that all audits have met these requirements. Additional materials for energy auditors can be found in Appendixes 2–9.

Customer interview

Prior to initiating the energy audit, auditors will interview customers to identify the customer's priority comfort and health concerns and other questions. Auditors will use the interview to explain the general audit process and procedures (including the technical processes), how information is gathered, and how that information will be used to create the Energy Conservation Plan. Efficiency Kansas qualified auditors are expected to keep customers involved to the greatest extent possible at all times. See sample questionnaire in Appendix 2.

Inspection

A thorough inspection is, obviously, essential to an accurate energy audit. Inspections performed by Efficiency Kansas qualified energy auditors will include the following components (all of which are detailed below):

- Assessment of building envelope: Exterior observation and measurements;
- Assessment of building envelope: Interior observation, measurement, and preparation;
- Combustion testing (health and safety);
- Assessment of mechanical systems;
- Treatment of duct leakage;
- Moisture control;
- Unvented space heaters; and
- Blower door / Air-tightness test.

Assessment of building envelope: Exterior observation and measurements.

The inspection of the building envelope will include the following:

1. ***Create plan view,*** illustrating the outline and dimensions of the structure. Many auditors find it helpful to begin consistently at a given point (say, the northwest corner of a structure) and measure in a particular direction (say, clockwise). Thus, all sides are viewed in a given order, reducing potential for confusion and duplication. The "plan view" drawing should indicate which way is North for easy reference.
2. ***Create elevation views,*** showing the overall shape and the location of doors, windows, and other features of each side or face of a structure. Effort should be made to produce an illustration that is neat and provides a reasonably accurate representation of dwelling. Photographs may be included as elevation views. Pictures must show all four sides of the house and also clearly show any relevant items to be addressed in work specification forms.
3. ***Measure doors and windows and assess shading and solar exposure.***
   a. Door and window dimensions are written with the width first, then the height.

b. Observation should be made during the measurement phase to determine whether work will be applied to doors and windows.
c. If no additional work will be applied on a given door or window, only rough opening measurements are required.
d. If replacement or repair work requiring more detailed measurements is determined to be necessary, detailed measurements should be taken
e. Define the degree to which windows are shaded, thereby reducing the amount of solar heat gain transmitted through them. Shade can be provided by blinds and curtains on the inside of windows, insect and solar screens on the outside, overhangs and wing walls which are part of the building's shape and form, trees and shrubs which may seasonally lose and gain foliage, and nearby buildings and land forms.

4. ***Check side wall construction and insulation factors.***
   a. Check to determine the feasibility of installing additional sidewall insulation.
   b. Document the type of siding, insulation, approximate R-value, and type of construction. Siding condition should also be noted.
   c. Siding removal should be included as an option in insulation bid packages.
   d. The existence of various types of replacement siding (i.e., steel, aluminum, vinyl, and asbestos-cement) will not necessarily constitute a justification to omit sidewall insulation unless extenuating circumstances exist and are documented. All types of installation should be considered including an interior installation using crown mold and chair rail to cover holes.
   e. The presence of sidewall insulation will not necessarily constitute a justification to omit sidewall insulation, unless extenuating circumstances exist and are documented.
   f. Auditors should complete their own sidewall tests, such as drilling test holes to determine whether sidewalls are insulated.
   g. It is important when conducting blower door tests to know whether or not sidewalls are insulated. Sidewall testing should not be conducted by insulation contractors.
   h. Test holes should be drilled in the same siding run used to add insulation. In some situations, it is possible to observe wall insulation by removing outlet and switch plates, or by drilling through interior walls in closets or behind cabinets.
   i. Uninsulated wall cavities on exterior walls shall receive blown cellulose insulation (if audit approved), unless circumstances make it impossible to install insulation. The presence of pre-existing insulation is not necessarily a reason to not insulate.
   j. Dense-packed, tube-filled insulating technique is the preferred method and should be included as an option in all insulation bid packages.
   k. The dense-packed method must be employed unless the wall condition prohibits its use.
   l. It is the auditor's responsibility to determine whether or not the walls are in a condition that allows for the dense-packed insulation method.
   m. If the dense-packed method is not used, the inspection report must document the reason.
   n. The State Energy Office will approve payment for insulation of only those sidewall areas that actually receive insulation.

o. All sidewall insulation bids will specify insulation of "net" wall area. Any payment to contractors for insulation of "gross" wall areas (doors, windows, etc., that <u>cannot</u> be insulated) is not allowed.

p. Document air sealing that can be done at utility bypasses, vents, and other penetrations that allow air leakage that is inaccessible from the interior

q. Examples might include the sill plate, band joist area in homes with very low crawlspaces, cracks or holes in foundations, and crawlspaces or foundation entry hatches.

r. Pre-blower door air sealing measures which can be accomplished only from the exterior of the dwelling should be noted during this phase.

5. ***Exterior observation of roof condition.***
   a. Determine if, and where, roof leakage problems may exist.
   b. Roof leaks may be sealed to protect the integrity of the structure.
   c. Roof leaks may be sealed to protect attic insulation.

6. ***Assess water-shedding functions of the dwelling.***
   a. Site drainage problems which cause moisture to enter the structure and may compromise the integrity of the structure and/or foundation can be addressed as repairs to protect the structure against moisture damage and related health and safety problems.
   b. A drainage swale could be cut to cause water to drain around the structure, or fill dirt could be added to cause water to drain from the structure.
   c. Other water-shedding or site drainage problems that are specific to the structure should be noted during this observation phase.
   d. A failing guttering system may result in moisture damage to the dwelling and may be addressed as repairs to protect the sidewall insulation.
   e. Gutters may be cleaned, repaired, replaced or installed as protective measures to prevent or repair water damage that could affect the performance of installed measures.

Assessment of building envelope: Interior observation, measurement, and preparation

The inspection of the building interior will include the following:

1. ***Inspect attic insulation.***
   a. Un-insulated or partially insulated attics shall be insulated to R-30 or R-38, according to the cost effectiveness as determined by audit analysis (SIR of at least 1.0).
   b. If no attic access exists, and it is not possible to obtain access through an exterior vent, then an attic hatch or access vent shall be installed. Blower-door-guided air-sealing work cannot be conducted properly without investigation of air leakage in the attic.
   c. "Access hatches" can be pre-fabricated using 1 × 10 lumber for the sidewalls (to act as an insulation dam), 1 × 4 lumber for ceiling trim, and a piece of ¾-inch plywood for the door. The pre-fabricated units can be sized to fit standard rafter widths of 16 inch and 24 inch on center.

d. If there is no hatch cover in place, then a temporary hatch cover shall be installed to complete blower-door testing.

e. Attic and crawlspace hatches in conditioned areas shall be weather-stripped to prevent air leakage, insulated to at least R-19, and shall remain operable after the job is completed.

f. Access hatches to knee-wall areas are subject to the same requirements. If no access to the knee-wall area(s) exists, one shall be installed.

2. ***Inspect wiring and heat sources in the attic.***

a. If knob-and-tube wiring (KTW) is present and attic insulation will be installed, auditors should test the wiring with a voltage detection device to determine whether or not it is active.

b. KTW is not inherently dangerous, but it is an older type of wiring that was not designed or installed with modern appliance loads in mind. Often, the KTW is a lighter gauge wire than is recommended for modern applications. Thus, KTW is potentially dangerous in situations where it can be overloaded, which may cause it to overheat and cause a fire.

c. The National Electrical Code requires that insulation material should not cover KTW. It is suggested, therefore, that insulation be "valleyed" under and around KTW or that insulation dams be installed to prevent contact with KTW. Special care should be taken to ensure that KTW splices remain visible and are not covered by insulation.

d. KTW must be protected by circuit breakers or S type fuses with an appropriate amperage limit for the gauge of wire used (15 amp for #14 wire, and 20 amp for #12 wire). S type fuses are designed to prevent both the installation of higher amperage fuses and the insertion of coins into the fuse holder for the purpose of circumventing fused amperage limitations.

e. Insulation can not be installed if the above precautions are not taken. Permission must be obtained from the owner to modify fuse box.

f. Insulation dams must be placed around any potential heat-producing sources, including recessed lights, chimneys, flues, and open electrical boxes.

g. Unfaced fiberglass batting may be used as an insulation damming material, but a three-inch air space must be maintained between any damming material and the heat source. Unfaced fiberglass batting, or any other damming material, must not touch the heat source.

h. Damming material must be sufficiently high to contain the specified depth of the insulation material to be installed. Damming material also must be sufficiently strong to ensure that the weight of the insulation product will not cause the damming material to move or collapse against the heat source.

3. ***Inspect ceilings.***

a. The stack effect in winter is perhaps the most constant and often the strongest driving force moving conditioned air and moisture vapor from a dwelling. Holes or penetrations in the upper plane of the interior envelope are, therefore, the most important air leaks to seal in a structure.

4. ***Inspect walls.***
    a. Holes or penetrations in interior walls, especially in balloon-framed structures, can allow conditioned air to move from the structure through interconnected framing conduits. Holes or penetrations that would allow insulation to blow into the living space must be sealed prior to the installation of the insulation.
5. ***Inspect floors.***
    a. Floors between stories in many houses contain open floor joist areas that can act as air passage conduits. Cantilevered areas—where an upper story juts over a lower story or where a bay window extends beyond the wall plan—can allow major air leakage. Many leaks through and between floors will be revealed by blower door tests. Dense-packed insulation can be used as an effective air sealant at the ends of floor joist cavities. Large, obvious penetrations should be repaired or temporarily sealed prior to the blower door test.
6. ***Assess ventilation.***
    a. Attic ventilation shall be installed so that there is one square foot (net) of free vent area in every 300 square feet of attic floor area, with approximately half of the vent area located near the roof ridge and the remaining vent area located near the eaves. However, the auditor must also take into account the leakiness of the attic and its particular moisture- and heat-retention characteristics when determining the proper amount and location of additional venting to recommend.
    b. Many older houses were originally constructed with spaced boards and have wood shakes or shingles that have a much higher natural ventilation rate than newer houses with plywood sheathing. Therefore, such structures may require less or no additional ventilation.
7. ***Inspect basement/crawlspace.***
    a. Auditors will look for signs of air leakage at penetration sites (including any windows and doors) and inspect the condition of rim joist insulation. Signs of moisture infiltration should be noted in the Audit Report to the customer.
    b. Infrared scans may be performed to confirm areas of heat loss and gain.
    c. The sill plate rim joist area in many homes is a major source of air infiltration. Stone foundations often contain numerous holes and cracks, which are major sources of infiltration. Cracks may be caulked, stuffed with backer rod or other packing material and caulked, sealed with an expanding foam product, or sealed in other ways that provide an effective and durable seal. Expanding foam products should be used only in areas that do not receive direct sunlight, or should be coated to protect them from such light (ultra-violet rays deteriorate the product and reduce its effectiveness).
    d. Batt or rigid-board insulation may be cut and placed neatly in the rim joist area if the auditing software determines that the addition of batt insulation to the perimeter would result in significant reduction of conductive heat loss. Rim joist insulation may also be installed using spray applied cellulose material.
    e. Basement grade entries, foundation entry doors, and crawlspace entry hatches should be inspected to ensure that they provide an effective barrier to the penetration of water and a durable air seal. Wood construction in contact with soil or near the grade

line should be of a treated nature. Foundation entry doors can be constructed of treated, braced plywood or can be standard exterior entry doors.

f. A six-mil poly vapor barrier should be installed over all dirt crawlspace floors if possible. The poly barrier can also help to make crawlspace inspection and repair work more pleasant, and it will contain the evaporation of moisture from the soil into the space above.

g. Crawlspace ventilation should be installed only if the site-specific situation precludes the installation of an effective vapor barrier and if there is reason to believe that ventilation is necessary to protect structural components from moisture damage.

h. Recent tests indicate that installation of a vapor barrier alone reduces the emission of moisture from dirt crawlspace floors sufficiently to protect the structure without opening additional infiltration pathways.

Combustion testing (health and safety)

Auditors will perform combustion appliance zone (CAZ) analysis on combustion appliances in the home. This will include looking for evidence of backdraft/spillage and any carbon monoxide leaks in the home. Auditor's recommendations should take into account health and safety precautions, to ensure safe operation of combustion appliances and that indoor air quality is maintained at a safe level. This testing shall be performed during test-in and test-out procedures.

Mechanical systems

In addition to the specific requirements below, auditors should identify the age and condition, make, model, serial number, and energy efficiency rating for all mechanical systems in the report accompanying the energy audit. See Appendixes 3-6 for applicable forms to be completed and submitted with the Audit Report.

1. Heating and cooling: Auditors will check performance of equipment, and ensure equipment is operating as intended (e.g., auditors will check any drain and condensate lines).
2. Water heater: Auditors will examine water heater for performance, temperature setting, and signs of leakage. If furnace or boiler system is being recommended for replacement and shares a flue system with the water heater that is not going to be replaced, note on the DWH form that the water heater will be 'orphaned'.
3. Distribution systems: Auditors will check condition of, and indicate any repairs that may be necessary for the following:
    a. Air handlers and coils
    b. Ductwork
    c. Steam/hot water pipes (for boiler)
    d. Mechanical ventilation (bath/garage exhaust fans)

Duct leakage

If duct system runs through unconditioned space in the attic, an unconditioned crawl space or basement, the ducting must be sealed and insulated. Auditors will follow the specifications listed below:

1. Fiberglass mesh tape shall be installed under mastic where needed for reinforcement.
2. Approved caulks and mastics shall be used for duct sealing.
3. Duct insulation shall have a minimum R-value of 4
4. Return-air systems in CAZ area should have seams sealed to prevent possibly pulling combustion gas by-products into the system and distributed through supply system.

Moisture control

Homes that have moisture problems such as leaky roofs or foundation problems, must have these issues corrected prior to implementing the energy conservation plan recommendations.

Existing moisture problems in a house may result from mechanical ventilation not being either installed or used by the customer/homeowner/tenant of the property. Mechanical ventilation should be installed and customers should be advised of hazards associated with moisture when doing daily water activities such as cooking or bathing. To help ensure that the moisture is eliminated from the home, the auditor should instruct the occupants about using ventilation fans for thirty minutes following any water activity to eliminate moisture from the house and help reduce the risk of creating a moisture damage problem in the structure. Mechanical ventilation should be exhausted to gable, roof, or soffit vent, not merely into the attic.

Auditors need to ensure the minimum ventilation guidelines have been installed per ASHRAE 62-89.

Unvented space heaters

Buildings heated by unvented space heaters are considered unsafe and shall not have air sealing or building tightness measures applied unless the heaters are removed from the premises, vented to the outside, or replaced with an appropriate heating unit (see Unvented Heater Removal Agreement, Appendix 4)

Blower door / Air-tightness test

Auditors will perform an air-tightness test using a blower door, a piece of equipment that allows an auditor to pressurize a house to determine the tightness of the home's shell, and identify ways to improve the home's shell. Auditors will take care to ensure health and safety regarding lead paint or asbestos materials, making all efforts to cause no harm to customers. Auditors will locate all areas of significant air infiltration/exfiltration including windows, doors, duct chases, etc., and report these to the customer. Auditors and contractors will ensure that minimum air ventilation guidelines, as per ASHRAE 62-89, have been met during both test-in and test-out procedures to provide for the proper amount of air changes per hour. Combustion appliance zone testing should be performed at a level equal to or exceeding guidelines established by the Building Performance Institute (BPI), Residential Energy Services Network (RESNET), and other Department of Energy (DOE) funded research.

All contractors and crew members will be responsible for complying with the EPA's Renovation Repair and Painting (RRP) regulations as enforced by the Kansas Department of Health and Environment. More information can be found at www.epa.gov/lead/pubs/renovation.htm. Also refer to EPA Final Rule [under the authority of 402 c 3 of the Toxic Substances Control Act (TSCA)], and New Lead Based Paint Renovation, Repair and Painting Program requirements (40 CFR 745, Subpart E), issued April 22, 2008 (73 FR 21692).

Inspecting mobile homes: Special considerations

Auditors inspecting mobile homes must have a special Mobile Home Certification. This training can be obtained at an Efficiency Kansas qualified training institution (see web site for list of such institutions: www.efficiencykansas.com).

Furnaces and ducting.—The interior observation process in mobile homes should start with a visual inspection of the furnace ducting system, then move to the upper plane of the interior envelope (i.e., the ceiling), and finally work through the main body of the house to the floor and possible penetrations into or through the underbelly.

Several types of air leakage sites are common to the furnace ducting systems of mobile homes. The boot that connects the duct to the floor of the trailer is often the site of major air leakage. In many mobile homes, it is possible to lift a floor register and see into the underbelly, or see the ground under the structure through holes in the duct boot and the underbelly.

In some older mobile homes, the ends of units of ducting have been compressed to connect them to other units to form longer ducting runs. As a result, there are often air leaks at the top and bottom of the duct where the two units of ducting join. In addition, the ends of ducting runs are either poorly sealed or not sealed at all. In double-wide units, the duct that joins the two sides is often loose or misaligned.

Leaks in the supply ducting of mobile homes allow conditioned air to be blown into the underbelly or outside the house, when the furnace blower is functioning, significantly reducing the efficiency of warm air delivery within the structure. When the furnace blower is not functioning, the same leaks allow outside air to blow back into the structure. No air movement within or through the ducting system should be observed when the blower fan is not operating.

Framing.—In the assembly process of most mobile homes, the roof structure is installed as a complete unit after the frame, floor, and walls have been constructed. The completed roof section is lifted into place with a crane and set upon the wall structure; this creates some potential for air leakage at the roof/wall joint. Appropriate sealing material may be applied on both sides of the trim piece at the roof/wall joint. However, sealing the joint between interior partition walls and the ceiling should rarely be necessary.

Holes, cracks, and penetrations in the ceiling may constitute important air leaks

Walls and windows.—Holes or penetrations on the inside of exterior walls of mobile homes can allow air to move from the structure through the corrugated exterior siding.

In almost every case, some type of interior storm window will provide the most effective, and the most cost effective, reduction of air infiltration through mobile home windows. Recent research on mobile homes has indicated that window replacements should be used *only* when repair would be more expensive than replacement. Even for jalousie and awning windows, money is better spent on interior storm panels than on window replacement.

It is often possible (with client approval) to seal some primary windows shut if they are not normally used for ventilation.

Other Repairs.—Floors in mobile homes are often constructed of particle or wafer board. Moisture generally causes this type of material to deteriorate rapidly. In mobile homes, plumbing leaks and other types of moisture concentration are a common occurrence. Floor repairs may be completed using treated lumber to provide some protection against future deterioration. Caution should be used in the handling of treated material due to the toxic nature of the chemicals used in the material.

Exterior doors that are misaligned due to settling of the unit may allow water leakage. It is not uncommon to find floors around exterior doors deteriorated due to moisture damage. Condensation on windows, especially replacement type windows without interior storms, can cause deterioration of the walls and floors below the window. Plumbing leaks under kitchen and bathroom cabinets, bathtubs, water heaters, washing machines, and refrigerators may also cause floor deterioration.

Post-retrofit Audit

Auditors must perform a post-retrofit audit to ensure that all measures have been installed properly as designed by the audit. The post-retrofit audit will include the following:

1. Examination of all components of the Energy Conservation Plan to ensure they were installed properly.
2. Performance of a blower-door test, ensuring strict adherence to ASHRAE Standard 62-89 for minimum air change calculations.
3. Performance of combustion appliance zone testing should be at level equal to or exceeding guidelines established by BPI, RESNET, and other DOE funded research.

Upon completion of the post-retrofit audit, auditors will sign and submit the Efficiency Kansas Certificate of Project Completion to the customer, whose signature is also required for project to be considered completed and financing approved by the State Energy Office.

Bids for Recommended Improvements

The auditor will provide the customer with a list of recommended improvements. Customers will be responsible for soliciting bids for each of the recommended improvements as listed by the auditor. Although customer are not required to take the lowest bid, the amount spent on the improvement must meet the cost-effectiveness standards discussed in section 2.3. Customers will receive final bids from contractors prior to submitting the proposal to the bank or utility and will have them sign the Contractor Terms and Conditions form (Appendix 7).

The invoiced amount(s) can be no more than the accepted bid(s) unless the contractor(s) gain written approval from the customer to deviate from the original bid. Under no circumstances will the State Energy Office finance more than the maximum amount approved in the Energy Conservation Plan. Auditors are encouraged to write specifications in great detail, in order to ensure that recommended improvements achieve the projected savings. Customers will ensure that all selected contractors sign the required Davis-Bacon Acknowledgment (see Appendix 8).[1]

All contractors and crew members will be responsible for complying with the EPA's Renovation Repair and Painting (RRP) regulations as enforced by the Kansas Department of Health and Environment. More information can be found at www.epa.gov/lead/pubs/renovation.htm. Also refer to EPA Final Rule [under the authority of 402 c 3 of the Toxic Substances Control Act (TSCA)], and New Lead Based Paint Renovation, Repair and Painting Program requirements (40 CFR 745, Subpart E), issued April 22, 2008 (73 FR 21692).

Project Financing

A Certificate of Project Completion (or its equivalent for meter-based utility programs) must be signed by the customer before funds will be dispersed by the State Energy Office (see Appendix 9). In addition, invoices must be included from participating contractors that clearly indicate the work completed including itemization of materials and labor where appropriate, serial and model numbers of equipment installed, or anything else necessary for the State Energy Office to clearly identify that the invoices are consistent with the Conservation Plan are required prior to the funds being dispersed.

Davis-Bacon Act

Projects funded through the Efficiency Kansas revolving loan program may be subject to requirements of the Davis-Bacon and Related Acts (DBRA). This may require contractors and subcontractors performing energy efficiency improvements under the Efficiency Kansas programs (whether accessed through utility or bank track) to pay workers the Davis Bacon prevailing wage rate for the area. This rate is established by the United States Secretary of Labor and is a requirement of all ARRA funds.

Each contractor's bid shall include the Davis-Bacon Acknowledgment form.[2] The contactor shall certify that all workers are (1) paid no less than the Davis-Bacon prevailing wage rate for the area or (2) provide the reasons why the proposed project is not subject to Davis-Bacon requirements.

2.3 Energy Audit Report Specifications

Another key piece of a Efficiency Kansas approved energy audit is the report that the auditor prepares following the inspection. The Audit Report, which includes general information and the

[1] The State Energy Office is awaiting further guidance from the Department of Energy on Davis Bacon requirements.
[2] The State Energy Office is awaiting further guidance from the Department of Energy and will provide this Acknowledgment form at a later date.

Energy Conservation Plan, provides both a detailed "diagnosis" and a "prescription" with options for the customer to review.

Every Audit Report will be reviewed by the State Energy Office and recommended projects approved before funds are released from the Efficiency Kansas loan fund.

Mandatory Audit Information and Submittals

Every Efficiency Kansas energy audit report must include the following specific information:

1. Site Data Collection Forms (see sample in Appendix 3): This information should be thorough and clearly indicate all measurements, notes, conditions, and computer data inputs. It is necessary that this information be precisely detailed with information that would allow the re-creation of the entire audit at any future date.
2. Photos: Portrait elevation views of all sides of the building.
3. Mechanical Testing Forms (all appropriate forms are located in Appendix 5).
4. Unvented Space Heater Agreement (see Appendix 4).
5. Historical Fuel Consumption: Auditors will obtain 12 months of utility information for each fuel source used in the structure and will provide customers with unit costs, average use, and average costs (annual and monthly) for each fuel source.
6. Computerized Audit: Include software name and version number.
7. Energy Conservation Plan.
8. Building File Report from REM/Rate or REM/Design.

Auditors should provide customers with the appropriate number of the Contractor Terms and Agreement Forms (see Appendix 7) when they present the energy conservation plan to the customer. As discussed in Sections 3 and 4, it is the customer's responsibility to solicit bids from contractors (these will be included in the information they provide to the utility or bank).

Energy Conservation Plan

The Audit Report will include an Energy Conservation Plan that will detail the recommended improvements. These recommended improvements will be prioritized in terms of importance.

Necessary repairs to existing infrastructure

First and foremost, the Energy Conservation Plan will detail any "as-built" repairs needed to ensure the health and safety of structure's occupants; examples include repairing faulty equipment (faulty pilot lights on gas furnaces and/or water heaters), and improper sizing and installation of combustion appliance vent piping.

Priority listing of energy conservation and efficiency improvements

These improvements and the priority in which they should be implemented shall be identified by the analytical software utilized in preparation of the approved energy audits (see Section 2.1). The following types of improvements may be included in Energy Conservation Plan:

1. Envelope improvements: e.g., installing additional insulation; sealing leaks.
2. Ductwork or air-handler improvements.

3. Cooling load reductions: e.g., solar shading/tinting, awnings.
4. Solar water heating systems (passive and/or active).
5. Replacement of heating and cooling (HVAC) equipment; note that no HVAC equipment will be approved without first addressing problems with the envelope.

Priority listing *may* also include water conservation measures and/or renewable energy generation, provided such improvements are cost effective and permanently attached to the structure.

Mandatory minimums for equipment replacements

Projects that recommend replacement of HVAC equipment must meet the minimum efficiency standards and other requirements listed below.

1. Furnaces must have an AFUE of at least 92%.
2. Air Conditioners must have a minimum SEER of 14.
3. All equipment must be installed per the manufacturer's specifications.
4. All manuals and warrantees must be left with the customer.

Cost-effectiveness of recommended improvements

In order to qualify for financing through the Efficiency Kansas loan program, all improvements must (1) have a Simple Payback within 15 years and (2) projected energy and dollar savings must be realized within the "life-cycle" of the equipment, which can not exceed 15 years for the purpose of calculating the Simple Payback. The life-cycle of equipment is defined by the Database for Energy Efficient Resources (DEER) of the California Energy Commission (available online at http://www.energy.ca.gov/deer/). Measures that require more than 15 years to provide a Simple Payback within 15 years may qualify for Efficiency Kansas financing if the Customer is willing to buy down some of the project costs (make an upfront payment for the additional costs) so that the total project will meet the 15-year Simple Payback (see Appendix 1 for cost-effectiveness calculations).

Permanence of recommended improvements

In addition to the cost-effectiveness criteria outlined above, all improvements must be a permanent fixture to the building in order to qualify for financing through the Efficiency Kansas loan program.

Non-approved improvements

The Audit Report may contain items and recommendations that will not be approved by the State Energy Office, but may be valuable for the customer. Such improvements include appliance upgrades or other measures that are not permanently attached to the structure. Savings from these items can not be included in the Simple Payback calculation.

Cost of each improvement

The final Energy Conservation Plan should include detailed and final costs for each recommended improvement prior to submission to the utility or bank. The submission should include bid sheets from contractors as verification of the costs identified in the Energy

Conservation Plan. These costs are considered final; no requests for additional funds will be approved in the event of cost overruns.

Projected savings

The Energy Conservation Plan should include a detailed calculation of projected savings, based on actual historical usage, for each fuel source used. Calculations and assumptions should be clearly identified. Auditor will analyze at least twelve (12) months of the most recent utility bill information (electric, gas, propane, etc.) for the purpose of determining accurate savings estimates. Savings and payback projections will be included for each measure individually, as well as for the comprehensive package of improvements. Auditors shall complete and submit the Energy Savings Report (Appendix 6).

Monthly costs (utility track only)

Auditors will calculate the monthly program charge that will be included on utility customer's monthly bills (see Appendix 1 for more information on calculations). In order to qualify for Efficiency Kansas financing, the repayment term can not exceed 15 years (180 months) and the amount of the monthly charge can not be more than 90% of the projected average monthly savings. In other words, the monthly charge for a project with projected average monthly savings of $100 may not exceed $90. Note that the calculation of savings will be based on estimated reductions in both electricity and natural gas usage, where applicable. The monthly charge will also include a $2.00 monthly fee to cover State Energy Office administrative costs and may also include an administrative fee for the Utility.

Health and safety considerations

Auditors will identify and list all combustion appliances and systems, the test performed, and any repairs or replacements necessary to ensure the health and safety of building occupants. Auditors and contractors will ensure that minimum air ventilation guidelines as per ASHRAE 62-89 have been met during both test-in and test-out procedures to provide for the proper amount of air changes per hour. Combustion appliance zone testing should be performed at a level equal to or exceeding guidelines established by BPI, RESNET, and other DOE funded research. Auditors will recommend installation of carbon monoxide detector.

General Provisions

Audit expiration

Audits and Energy Conservation Plans shall expire one (1) year from the date of initial audit. Customers who do not elect to move forward with a project during this time frame will be required to have another audit, should they wish to access Efficiency Kansas financing through either the bank or utility track.

Fuel switching (utility track only)

If the Energy Conservation Plan recommends improvements that necessitate a change in the type of fuel currently used (for example, a gas furnace being replaced by an air-source heat pump), the Audit Report must include the costs and projected energy savings for both the recommended equipment and fuel, and costs and savings associated with updated equipment using the current fuel source.

Liability

Auditors must include the following language on all contracts, paperwork, and the Audit Report provided to Customer: "The Kansas Corporation Commission does not endorse, approve, or recommend any energy auditor, contractor or subcontractor associated with the Audit Report, proposed energy efficiency improvements, or contract for energy efficiency improvements. No guarantees or warranties, express or implied, are made by the KCC or the State Energy office with respect to any audit report, estimated savings, proposal for improvements, contract for improvements or any work or equipment included as part of the customer's energy efficiency project funded through the Efficiency Kansas revolving loan program. It is recommended that customers exercise due diligence in the selection of an energy auditor or contractor prior to entering into any contract or agreement for energy efficiency improvements. Customers may request references of an energy auditor or contractor and should always insist that any guarantees and warranties represented by an energy auditor or contractor, either for workmanship or equipment warranties, are provided in writing."

Contractor Requirements

As noted above, projects funded through the Efficiency Kansas revolving loan program may be subject to requirements of the Davis-Bacon and Related Acts (DBRA). This may require contractors and subcontractors performing energy efficiency improvements under the Efficiency Kansas programs (whether accessed through utility or bank track) to pay workers the Davis Bacon prevailing wage rate for the area. This rate is established by the United States Secretary of Labor and is a requirement of all ARRA-funded programs.

Each contractor's bid shall include the Davis-Bacon Acknowledgment form.[3] The contactor shall certify that all workers are (1) paid no less than the Davis-Bacon prevailing wage rate for the area or (2) provide the reasons why the proposed project is not subject to Davis-Bacon requirements.

Auditors should provide customers with the appropriate number of the Contractor Terms and Conditions Forms (see Appendix 7) when they present the Energy Conservation Plan to the customer. As discussed in Sections 3 and 4, it is the customer's responsibility to solicit bids from contractors (these will be included in the information they provide to the utility or bank).

All contractors and crew members will be responsible for complying with the EPA's Renovation Repair and Painting (RRP) regulations as enforced by the Kansas Department of Health and Environment. More information can be found at www.epa.gov/lead/pubs/renovation.htm. Also refer to EPA Final Rule [under the authority of 402 c 3 of the Toxic Substances Control Act (TSCA)], and New Lead Based Paint Renovation, Repair and Painting Program requirements (40 CFR 745, Subpart E), issued April 22, 2008 (73 FR 21692).

[3] The State Energy Office is awaiting further guidance from the Department of Energy and will provide this Acknowledgment form at a later date.

2.4 Monitoring by the State Energy Office

The State Energy Office will monitor projects on a continuing basis to ensure that Efficiency Kansas Participants receive excellent service. This monitoring will include (1) the review of all Energy Reports (including Energy Conservation Plans) prior to approving projects for financing through the revolving loan fund; (2) the performance of random "performance" audits before or after the project's completion; and (3) interviewing Participants to ensure their satisfaction and to determine ways to improve customer service.

Should the State Energy Office find unsatisfactory work, incomplete audits, or other problems causing customers to be unsatisfied, auditors and contractors may be barred from further participation in the program.

Section 3: Guidelines for Utility Track

As discussed in Section 1, Kansans can access the Efficiency Kansas loan program in one of two ways—through Partner Utilities and Partner Banks. In the utility track (as with the bank track), 100% of the project cost will be financed through the Efficiency Kansas loan program, up to a maximum of $20,000 for improvements in existing homes and $30,000 for improvements to existing small commercial and industrial structures.

Utilities are considered Efficiency Kansas "Partner Utilities" if they offer programs that facilitate energy conservation improvements in residential and small commercial/industrial that are consistent with the KCC goals described in Section 1.1 and plan to either utilize Efficiency Kansas financing or collect loan payment on utility bills for Partner Banks.

Programs offered by Partner Utilities are likely to vary, with some utilities offering full, meter-based programs, similar to the existing How$mart® program at Midwest Energy, and others offering a program that is not meter-based. In all instances, however, all projects receiving funds through Efficiency Kansas must be repaid in 15 years or less.

Utilities subject to the jurisdiction of the KCC may become Partner Utilities upon approval of the Utility's program and associated tariffs by the Commission.

3.1 Utility Requirements and Responsibilities

Eligibility Screening

Utilities are responsible for establishing the eligibility of interested customers. To be eligible for Efficiency Kansas financing, utility customers (1) must be current on their utility payments and (2) must not have had their utility service disconnected in the 12 months prior to their application for participation. Customers who do not have 12 months history with a utility will be asked to provide payment history with previous utility. Customers on payment plans do not meet these eligibility requirements.

Subject to approval from the KCC and State Energy Office, utilities may use additional eligibility criteria.

Definition of residential and commercial customers

Residential customers are defined as all customers taking service under the utility's Kansas residential tariff.

Commercial customers must subscribe for service under one of the utility's applicable Kansas commercial or industrial service tariffs and use residential-sized HVAC equipment in their buildings.

Rental properties

For rental properties, whether residential or commercial, the utility customer may be either the landlord or the tenant. In either instance, the eligibility screening is the same as outlined above. For rental properties, the utility will also be required to ensure that both the tenant and landlord are informed and agree to participation in the meter-based program and ensure that all required measures for disclosure and notice are met (see below for discussion of disclosure and notification requirements).

Directing Customers to Energy Auditors

Utilities will direct eligible customers to the list of Efficiency Kansas qualified auditors (or to the utility's qualified employee auditors). Customers will select an auditor from this list or utilize the utility employee auditor to perform the required energy audit and develop the Energy Conservation Plan.

"Qualified auditors" are those who have met the criteria established by the State Energy Office and have requested that they be included in the listing of qualified auditors. This list will be maintained by the State Energy Office and be available on the Efficiency Kansas web site. All energy auditors on the Efficiency Kansas qualified auditor list will have undergone training and been certified by one of the qualified training institutions (see Section 2.1).

Qualified energy auditors are not recommended, approved, or endorsed by the State Energy Office or the Kansas Corporation Commission.

Facilitating Approval of Energy Conservation Plan (ECP) and Customer Projects

Following the energy audit, customers will review the prioritized recommendations outlined in the Energy Conservation Plan (ECP) and decide on the scope of the project. The utility will receive the ECP from the customer and forward to the State Energy Office for review; the utility will send the ECP's as they get them from the customers, rather than sending them in batches at regular intervals.

Following the State Energy Office review, the utility will notify the customer of approval or disapproval. Once the State Energy Office has approved a project, no adjustments can be made in the project costs.

Upon approval of an ECP, the Utility will sign the necessary agreements with the customer. These agreements will include requirements for the customer to disclose the meter-based obligation to subsequent occupants of the residential or small commercial/industrial structure.

Once all necessary agreements have been signed, the utility will inform customers that contractors can begin work on approved projects. Utilities may work with customers to select contractors. In all instances, the utility will be responsible for paying contractors (as detailed below).

Verifying Completion

After contractors have completed their work and the auditor has performed the required post-test, the customer and auditor will provide the utility with a signed Certificate of Project Completion (Appendix 10). The utility will sign the Certificate of Project Completion, indicating acceptance of the auditor and customer's assurance, and send the certificate to the State Energy Office. Utilities have the option to conduct an on-site inspection before signing the Certificate of Project Completion.

Receiving Efficiency Kansas Funds from the KCC

Utilities will receive funds from the KCC based on a regular monthly payment schedule (they will need to first complete Utility Contact Form, Appendix 10). Payment will be based upon the project costs submitted to the KCC State Energy Office with the Energy Conservation Plan. See detailed discussion of repayment of funds to the KCC below.

Paying Contractors

Upon receipt of funds from the State Energy Office, the utility will promptly pay all contractors for completed work.

Placing Charge on Bill

After paying the contractors for all approved project costs, the utility will place the program charge on the customer bill. The customer will be notified of this charge *prior* to the utility submitting the Energy Conservation Plan to the State Energy Office, as required in the Energy Audit Specifications (see Section 2.2 of this manual).

Term of the obligation

The maximum term of the meter-based obligation cannot exceed 15 years (180 bill payments). Utilities and customers may choose a shorter repayment period, provided all other requirements are met.

Program charge as a percentage of projected savings

In calculating the program charge, the utility will assume that all savings are annualized, resulting in a level (or average) monthly repayment. Under no circumstances will the program charge exceed 90% of the estimated total savings from all fuel sources (see discussion of administrative fees below). Although the utility offering the program may only provide one fuel type (e.g., natural gas and electricity), the calculation of projected savings will include all savings from all fuels.

Utility administrative fees

Utilities will be allowed to charge administrative fees to cover the costs of administering their program. Regulated utilities must have their administrative fees included in the tariff for the program, which is approved by the Kansas Corporation Commission. Non-regulated utilities must submit their proposals for administrative fees, including estimated costs to operate the program, to the State Energy Office.

Before customers agree to move forward with the project (and agree to repaying project costs as part of their monthly utility bill), they must be informed by the utility that the monthly program charge will include the State Energy Office and utility administrative fees.

The State Energy Office reserves the right to examine the administrative fees charged by regulated and non-regulated utilities participating in the Efficiency Kansas program.

State Energy Office administrative fees

The program charge will include a $2.00 administrative fee that will be collected by the utilities and paid to the State Energy Office. The customer must be informed of the State Energy Office administrative fee *prior* to the customer agreeing to the project. The program charge, including the administrative fees of the utility and State Energy Office, cannot exceed 90% of the expected savings.

Level payment plan option

Customers may elect to enter into a level, or average, payment agreement with the utility. Customers who elect not to have a level payment plan should understand that their actual savings may vary monthly and seasonally. The program charge will be a level payment, regardless of when actual savings are achieved.

Payment-in-full option

Utilities are required to offer customers the option to pay in full any remaining balance, at any time during the repayment term. There will be no penalty or extra charge for customers who choose to repay the obligation in full.

If a customer sells or transfers ownership of property subject to meter-based payments for energy efficiency improvements, the customer may pay the remaining balance in full, or the new property owner may complete the paperwork to assume the remaining balance.

Repayment of funds to KCC

Utilities are responsible for remitting to the KCC the full amount of the project cost received from the Efficiency Kansas revolving loan fund. The KCC will allow utilities to choose between two repayment options, designated Option 1 and Option 2. As described in more detail below, the options differ in how funds are remitted to the utility and how they are repaid by the utility to the KCC.

Option 1

In this option, the utility will receive funds from the KCC, on a regular monthly schedule, only after the State Energy Office has received a signed Certificate of Project Completion for each project. *Under Option 1, the utility is responsible for submitting monthly payment to the KCC, only upon receipt of payment from the customer.* See discussion of customer default below.

Frequency.—Utilities will make regular monthly payments to the KCC. However, utilities will only submit payments for those meters at which the customer has paid the monthly bill. If a customer has not paid the bill, the utility will not be required to remit payment for that meter to the KCC, until payments resume.

Reporting.—Because this option allows for deferral of payments to the KCC, the utility will be required to report the status of each meter obligation—location of the meter and the total remaining obligation—to the KCC on a monthly basis. Likewise, the utilities will be required to identify which meter obligations have been paid and which have not.

Case of default.—In the event that customers fail to make their monthly payments of the program charge, the utility will be required to report to the KCC, on a monthly basis, information regarding the collection status and disconnections resulting from the non-payment. The utility is expected to make every effort to collect payment of delinquent program charges and to exercise as much due diligence with collection of Efficiency Kansas revolving loan program funds as they would their own capital. At such time as the utility determines that it has exhausted its means of collection, the utility will notify the State Energy Office and submit the "Verified Statement" form, as stipulated in the Memorandum of Agreement Between the Utility and the KCC.

Option 2

If utilities select this option, they will receive funds from the KCC earlier in the process—upon approval of the Energy Conservation Plan by the State Energy Office.[4] Unlike Option 1, *under Option 2, the utility is responsible for submitting monthly payment to the KCC, regardless of whether the customer has paid the utility bill.* Utilities will begin making monthly payments to the KCC, once the Certificate of Project Completion has been signed.

Frequency.—Utilities will make regular monthly payments to the KCC for all meter-based program charges, whether the utility has received payment from their customers.

Reporting.—Under this option, the utility reports the status of each meter-based obligation on a quarterly basis (not a monthly basis, as required in Option 1). The utility will submit a quarterly report to the KCC, identifying the location of the meter and total remaining obligation.

Case of default.—In the event of nonpayment by the customer, the utility will still remit payment to the KCC until the full cost of approved project has been repaid. The utility will be responsible for collection from customer and can request recovery of bad debt in a regular rate case; such recovery may or may not be approved by the Commission.

Revert to Owner

Regardless of the repayment option chosen, utilities will be required to continue charging the program charge, even for meters that have a revert-to-owner clause. As long as a bill is generated during the 15-year term, the bill must include the program charge.

[4] In the event that approved project is not completed within six (6) months of the Energy Conservation Plan approval, the utility must return the funds to the KCC.

Disclosure and Notification Requirements

To ensure that subsequent occupants of a residential or small commercial/industrial structure receive full and timely notification of the program charge they will be assuming (i.e., the remaining obligation on the meter), the utility is required to provide written notification of this obligation to customers when service is initiated at locations that already have meter-based obligations. The utility must also require all customers to sign an agreement requiring similar disclosure by the customer to subsequent occupants. The KCC will require such agreements to be part of approved program tariffs.

UCC filing

In addition to the disclosure and notification requirements outlined above, the utility will also be required to file a UCC for each property with a meter-based obligation. The utility will be responsible for ensuring that any such UCC filing is renewed to ensure that proper notification occurs.

Additional public information and outreach

The State Energy Office will coordinate with utilities and others (e.g., realtors and their trade associations in areas offering meter-based programs) to increase public awareness.

Prudent Procedures

In establishing the guidelines for meter-based energy efficiency programs, utilities must properly document all transactions and include notices to the customer of the following: (1) interest rates, (2) repayment terms, (3) fee structure, (4) collateral requirements, and (5) procedures for collection and recovery actions. Even if the above are not applicable, documentation must clearly state that they are not applicable (for example, state that interest rate is 0%). As discussed above, UCC and any other applicable notice requirements must be filed to provide sufficient notice to future occupants and owners. Proper documentation will be accomplished by submission of Efficiency Kansas program forms, which will be developed by the KCC and included in a subsequent version of the Program Manual.

3.2 Customer Responsibilities

Obtaining Utility Information

Before contacting auditors, customers should obtain 12 months of their utility information—showing both their electricity and natural gas (or other heating source) usage. It is the Customer's responsibility to obtain this information from the utilities. This information will be needed in order for the Auditor to calculate estimated savings for proposed improvements.

Arranging Audits

Customers may select any energy auditor from the list of qualified auditors maintained by the State Energy Office and posted online (www.efficiencykansas.com). The customer arranging for the audit is entirely responsible for paying for the energy audit, regardless of whether the recommended project is approved by the State Energy Office for Efficiency Kansas financing or whether the Customer decides to move forward with an approved project.[5]

Participants may be eligible for the promotional rebate program offered by the State Energy Office to the first 1,000 participants who elect to move forward with approved project. See Efficiency Kansas web site (www.efficiencykansas.com) for more information about Energy Audit Rebate program. Utilities may also offer rebates of energy audit costs; however, rebates offered by regulated utilities will need to be approved by the KCC.

Selecting contractors

Prior to submitting the proposal to the utility, and approval by the State Energy Office of the Energy Conservation Plan and selected project, the customer will select contractors to perform the work. As discussed previously (see Sections 2.2, 2.3), customers will be responsible to receive bids for the work. The customer should be sure to receive final and complete bids, as no change orders increasing the price will be allowed after the Energy Conservation Plan is submitted to the utility.

Auditors should provide customers with the appropriate number of the Contractor Terms and Conditions Forms (see Appendix 7) when they present the energy conservation plan to the customer. As discussed in Sections 3 and 4, it is the customer's responsibility to solicit bids from contractors (these will be included in the information they provide to the utility or bank).

All contractors and crew members will be responsible for complying with the EPA's Renovation Repair and Painting (RRP) regulations as enforced by the Kansas Department of Health and Environment (see Section 2 for more details).

Submitting Energy Conservation Plan to Utility

After receiving bids from contractors, the Customer will submit to the utility the full audit and Energy Conservation Plan received from the auditor. The submission will detail the costs of the specific improvements, for which the Customer wishes to receive Efficiency Kansas financing, as well as all information the Customer received from the auditor and contractors. As discussed in Section 3.1, the utility will submit the Energy Conservation Plan to the State Energy Office.

Payment to Utilities

The customer is responsible for repayment of the monthly program charge, which will include the cost of the approved project and the administrative fees (see discussion of program charges in Section 3.1). Because the program charge in KCC-approved meter-based programs is considered "regular utility service," customers who do not pay their bill, or pay only a portion thereof, are subject to having their utility service disconnected.

As specified in Section 3.1, the utility must notify the customer of this charge *prior* to the utility submitting the ECP to the State Energy Office.

[5] The KCC may approve meter-based programs in which the utility pays for the cost of the audit, as with Midwest Energy's KCC-approved How$mart® program.

Maintenance of Equipment

The customer is responsible for all maintenance of equipment and should solicit and receive information on maintenance from the contractors that install the equipment. The customer should recognize that properly maintained equipment will provide better results and more sustained savings. Should the equipment fail, the customer is still responsible for paying the monthly program charge on their Utility bill.

Disclosure

Customers that agree to participate in the program are required to disclose to subsequent occupants any obligation that remains on the meter (i.e., remaining monthly payments). As a condition of participation in their meter-based program, the Utility will have customers sign disclosure agreements (see discussion of disclosure and notification requirements in Section 3.1).

Owner-occupants

Customers who own the home or small commercial/industrial structure must sign an agreement with the utility stating that they will disclose the meter obligation upon sale of the structure. Failure to make proper disclosure could result in the customer being responsible for immediate repayment of the remaining balance.

Rental properties

Landlords must disclose an existing meter obligation to tenants prior to their signing a lease if the tenant will be responsible for the utility bill.

Landlords and Tenants

Tenants wishing to participate in the program must have agreement from landlords in order to participate in Utility meter-based program. Conversely, landlords must have agreement from current tenants (unless the landlord also pays the utility bills). As noted above, landlords must also disclose to all tenants an existing meter obligation prior to the tenants' signing a lease.

3.3 KCC and State Energy Office Responsibilities

Management and Oversight

The State Energy Office will manage all aspects of the Efficiency Kansas loan program for both the utility and bank tracks. The State Energy Office will ensure that all program participants, including utility customers, receive high-quality service at each step of the process.

The KCC Utilities Division will review the applications of regulated utilities for a meter-based program and make recommendations to the Commission regarding approval of the program. The application for a meter-based program should include the content outlined by the Commission in Docket No. 08-GIMX-441-GIV, Appendix A (available on the KCC web site at http://kcc.ks.gov/scan/200811/20081114142730.pdf). The KCC Utilities Division will also coordinate the evaluation, measurement and verification associated with all utility-sponsored energy efficiency programs.

Review and approval of Energy Conservation Plan

The State Energy Office will review all Energy Conservation Plans to ensure that auditors have performed the audit properly, that savings estimates are appropriate and realistic, that project costs are not unreasonable, and that health and safety standards have been met. See Section 2 for audit specifications and other related information.

Field inspection

The State Energy Office will perform random field inspections to ensure that projects have been properly executed. Inspections will include full audits, inspection of systems installed, and interviews with customers.

Payment to utilities

The KCC will make payments available to the utility on a monthly basis. Depending on the option selected by the utility (see Section 3.1), the funds will be released upon the State Energy Office's approval of the Energy Conservation Plan (Option 2) or upon receipt of the Certificate of Project Completion (Option 1).

Maintaining online information

The State Energy Office will be responsible for ensuring that information on Efficiency Kansas web site is accurate. Such information will include, but not be limited to, the listing of Efficiency energy auditors and of Partner Banks and Partner Utilities.

Tracking availability of Efficiency Kansas funds

The State Energy Office, working with the KCC's Fiscal Division, will track the availability of funds in the Efficiency Kansas revolving loan fund. A waiting list will be established if funds are not immediately available, and payments to utilities will be processed from the waiting list in the order in which they were received.

3.4 Coordinating with Partner Utilities on Promotion

The State Energy Office will coordinate closely with Partner Utilities (and Partner Banks) on the marketing and promotion of both the utility's meter-based programs (as described above) and Efficiency Kansas. The State Energy Office's marketing campaign will highlight Partner Utilities, while lightly marketing the state's oversight role in operating Efficiency Kansas.

The State Energy Office will involve interested Partner Utilities (and Partner Banks) in the development of marketing campaign. Marketing materials will be developed that can be customized for use by Partner Utilities (and Partner Banks).

Partner Utilities will include acknowledgement of the Efficiency Kansas loan program when promoting their meter-based program to their customers. Customers will contact utilities directly, and Partner Utilities will explain the process and goals of the program.

Branding/Co-branding

Partner Utilities will name and brand their meter-based energy efficiency program and service. The relationship between the utility's meter-based program (and brand) and the Efficiency Kansas loan program (and brand) will be expressed as a partnership. Promotional materials produced by the utility for programs that utilize Efficiency Kansas funds will include language expressing this relationship—for example, Midwest Energy's existing program might be promoted as "How$mart®, an Efficiency Kansas partner"—and will be required to display the Efficiency Kansas brand.

Section 4: Guidelines for Bank Track

As discussed in Section 1, Kansans can access the Efficiency Kansas loan program in one of two ways—through Partner Utilities and Partner Banks. In the banking track (as with the utility track), 100% of the project cost will be financed through Efficiency Kansas revolving loan funds, up to a maximum of $20,000 for home improvements and $30,000 for improvements to small commercial and industrial structures.

Partner Banks will offer Efficiency Kansas loans at a *fixed* interest rate of no more than 4% through 2010. Based on market conditions, the State Energy Office may, after December 31, 2010, adjust the interest rate cap for future loans, but this will not affect the fixed rate of existing loans. The term of these loans may not exceed 15 years. The State Energy Office will provide rebates to banks to cover $250 of loan origination fees.

4.1 Bank Requirements and Responsibilities

Eligible Banks

In order to participate in this Program, a bank must have its home office or a branch located within the State of Kansas as required by K.S.A. 75-4201(d). Institutions of the Farm Credit System organized under the *Federal Farm Credit Act of 1971* (12 U.S.C. 2001), Savings Banks, Savings and Loan Associations, and Credit Unions with offices located within the State of Kansas are also eligible (see Linked Deposit Participation Agreement, available online at the Office of the State Treasurer).

An updated listing of Partner Banks will be maintained by the KCC State Energy Office on the Efficiency Kansas web site.

Providing Program Information

In many instances, banks will be the first point of contact for Kansans interested in the Efficiency Kansas loan program and, thus, will need to be able to provide program information to potential participants. The State Energy Office will provide information packets to all Partner Banks.

Directing Customers to Approved Energy Auditors

Banks will direct customers (i.e., potential borrowers) to the list of Efficiency Kansas qualified auditors, which will be available online (www.efficiencykansas.com). Customers will select an auditor from this list to perform the required energy audit and develop the Energy Conservation Plan. (See discussion of pre-approval option below.)

Establishing Borrower Creditworthiness

Banks are responsible for reviewing each borrower's application to determine the borrower's creditworthiness. In the case of default by the borrower (see discussion below), the Bank is responsible for repaying the outstanding principal to revolving loan fund.

Banks will not make the loan until the State Energy Office has approved the customer's Energy Conservation Plan (see below for discussion of submitting the plan). However, banks may want to provide customers with pre-approval to eliminate the risk of the customer having to pay for an energy audit and not being approved for financing.

Submitting Energy Conservation Plan

The bank will receive the Energy Conservation Plan from the customer and pass along to the State Energy Office for review. Upon receiving the results of the State Energy Office's review, the bank will notify the customer of approval or disapproval. (If the plan is approved, the State Energy Office will also notify the Treasurer's office at this time, so that funds can be released to the bank; see discussion below in Section 4.4) Costs for approved projects can not be adjusted after the State Energy Office has approved the plan.

In the event that the customer's Energy Conservation plan does not meet Efficiency Kansas guidelines, the State Energy Office will inform the bank of the reason. Depending on the problem, the customer may choose to correct and resubmit the Energy Conservation Plan to the State Energy Office.

Receiving Efficiency Kansas Funds

Upon receipt of State Energy Office approval, banks will submit request for funds to the Office of the State Treasurer (see Participation Agreement, available online at the Office of the State Treasurer: http://www.kansasstatetreasurer.com/prodweb/pub_1.php). The Treasurer's Office will place a deposit with the bank from the Efficiency Kansas revolving loan fund; the interest rate for each linked deposit will be 0%.

The amount and duration of the linked deposit will be no greater than the amount and duration of the bank's loan to the eligible borrower (and shall not exceed program maximums). See Participation Agreement for more details (available online at the Office of the State Treasurer: http://www.kansasstatetreasurer.com/prodweb/pub_1.php).

Making Loans to Customers

Upon receipt of State Energy Office approval, banks will finalize loans with creditworthy borrowers. Loan rates shall be a fixed interest rate of no more than 4%.

Submitting Certificate of Project Completion

After contractors have completed work on the customer's approved project, and after the auditor has performed the required post-test, the customer and auditor will provide the bank with a signed Certificate of Project Completion (Appendix 9). The bank will send this to the State Energy Office.

Repayment of Funds to Treasurer's Office

Banks will forward all principal payments for Efficiency Kansas loans to the Treasurer on a quarterly basis and confirm each borrower's outstanding principal balance annually, as stipulated in Participation Agreement (available online at the Office of the State Treasurer: http://www.kansasstatetreasurer.com/prodweb/pub_1.php). In the event of default by borrower, the bank remains responsible for payment of the outstanding principal on the linked deposit.

Pledging Securities as Collateral

If the total State of Kansas deposits with any bank (from Efficiency Kansas or any other source) exceed the maximum amount insured by the Federal Deposit Insurance Corporation (FDIC) or any other federal agency backed by the full faith and credit of the U.S. Treasury, the bank is required to pledge securities acceptable to the Treasurer as collateral for the amount of the linked deposits plus accrued interest. See Participation Agreement (available online at the Office of the State Treasurer: http://www.kansasstatetreasurer.com/prodweb/pub_1.php) for more details.

Promotion

Participating banks will coordinate with the State Energy Office on promotion of the Efficiency Kansas loan program. The State Energy Office's marketing campaign will emphasize the role of Partner Banks (see Section) in facilitating the financing of cost-effective energy efficiency projects in Kansas homes and small businesses.

Branding/Co-branding

Banks will be expected to include the Efficiency Kansas name and brand, along with their own name and brand, in all communications related to the revolving loan program. The relationship between the Bank and the Efficiency Kansas revolving loan program will be expressed as a partnership.

4.2 Customer Requirements and Responsibilities

Obtaining Utility Information

Before contacting auditors, customer should obtain 12 months of their utility information—showing both their electricity and natural gas (or other heating source) usage. It is the customer's responsibility to obtain this information from the utilities. This information will be needed in order for the Auditor to calculate estimated savings for proposed improvements.

Arranging Audits

Customers may select any energy auditor from the list of Efficiency Kansas qualified auditors maintained by the State Energy Office and posted online (www.efficiencykansas.com). The customer arranging for the audit is entirely responsible for paying for the energy audit, regardless of whether the recommended project is approved by the State Energy Office for Efficiency Kansas financing or whether the customer decides to move forward with an approved project.

Participants may be eligible for the promotional rebate program offered by the State Energy Office to the first 1,000 participants who elect to move forward with approved project. See Efficiency Kansas web site (www.efficiencykansas.com) for more information about Energy Audit Rebate program.

Selecting contractors

Before submitting the Energy Conservation Plan to the bank, the customer will need to select contractors to perform the work. The customer should be sure to receive final and complete bids, as no change orders increasing the price will be allowed after the Energy Conservation Plan is approved by the State Energy Office.

As discussed previously, auditors should provide customers with the appropriate number of the Contractor Terms and Conditions Forms (see Appendix 7), when they present the Energy Conservation Plan to the customer. As discussed in Sections 3 and 4, it is the customer's responsibility to solicit bids from contractors (these will be included in the information they provide to the utility or bank).

All contractors and crew members will be responsible for complying with the EPA's Renovation Repair and Painting (RRP) regulations as enforced by the Kansas Department of Health and Environment (see Section 2 for more details).

Submitting Energy Conservation Plan to Bank

After receiving bids from contractors, the customer will submit to the bank the full audit and Energy Conservation Plan received from the auditor. The submission will detail the costs of the specific improvements, for which the customer wishes to receive Efficiency Kansas financing, as well as all information the customer received from the auditor and contractors. As discussed in Section 4.1, the bank will submit all of this information to the State Energy Office.

Repaying Efficiency Kansas Loan

The customer is responsible for repayment in full of the Efficiency Kansas loan, according to the terms of the loan with the Partner Bank. The loan repayment will include the cost of the approved project, as well as the interest charged by the bank.

The customer will also be charged a $2.00 monthly State Energy Office administrative fee, which the bank will submit quarterly to the Office of the State Treasurer.

Maintenance of Equipment

Customers are responsible for maintaining all equipment and should solicit and receive information on maintenance from the contractors that install the equipment. Customers should recognize that properly maintained equipment will provide better results and more sustained savings. Should the equipment fail, customers are still responsible for repaying the bank for the Efficiency Kansas loan.

4.3 Treasurer's Office Requirements and Responsibilities

General Management of Revolving Loan Fund

The Office of the State Treasurer will manage the Efficiency Kansas revolving loan fund, on behalf of the Kansas Corporation Commission (KCC), of which the State Energy Office is a division.

Establishing Eligibility of Partner Banks

The Treasurer's Office will ensure that all banks receiving Efficiency Kansas funds meet eligibility requirements, as outlined in Section 4.1 and as stipulated in Participation Agreement (available online at the Office of the State Treasurer: http://www.kansasstatetreasurer.com/prodweb/pub_1.php). Eligible banks (this includes institutions of the farm credit system, savings banks, savings and loan associations, and credit unions) must have their home office or a branch located within the State of Kansas as required by K.S.A. 75-4201(d).

Releasing Funds to Banks

Upon receipt of KCC State Energy Office's approval, the Treasurer's Office will release funds to banks. The Treasurer's Office will ensure that each bank pledges securities for the amount of any deposits that exceed the insurance provided by the FDIC in compliance with K.S.A. 75-4218.

Receiving Funds from Banks

The Treasurer's Office will collect principal payments from banks on a quarterly basis and deposit payments in the Efficiency Kansas revolving loan fund. The Treasurer's Office will notify the KCC in the event of default on a certificate of deposit. In the event of a default, the bank shall remain responsible for payment of the outstanding balance, as provided in Participation Agreement.

Reporting Requirements

The Treasurer's Office will provide the KCC with quarterly reports that list the number and value of linked deposits placed with Partner Banks, the number of jobs created or retained at the Office of the State Treasurer (as a result of administration of Efficiency Kansas revolving loan program). This information is required by the U.S. Department of Energy for all State Energy Program initiatives funded through the ARRA.

Invoicing the KCC

The Treasurer's Office will invoice the KCC on a quarterly basis for the recovery of administrative costs, banking fees, and any other transaction charges.

4.4 KCC and State Energy Office Responsibilities

Management and Oversight

The State Energy Office will manage all aspects of the Efficiency Kansas revolving loan program for both the bank and utility tracks. The State Energy Office will ensure that all program participants, including bank customers, receive high-quality service at each step of the process.

Review and approval of Energy Conservation Plan

The State Energy Office will review all Energy Conservation Plans to ensure that auditors have performed the audit properly, that savings estimates are appropriate and realistic, that project costs are not unreasonable, and that health and safety standards have been met.

Field inspection

The State Energy Office will perform random field inspections to ensure that projects have been properly executed. Inspections will include full audits, inspection of systems installed, and interviews with customers.

Maintaining online information

The State Energy Office will be responsible for ensuring that information on Efficiency Kansas web site is accurate. Such information will include, but not be limited to, the listing of Efficiency Kansas qualified energy auditors, Partner Banks, and Partner Utilities.

Tracking availability of Efficiency Kansas funds

The State Energy Office, working with the KCC's Fiscal Division, will track the availability of funds in the Efficiency Kansas revolving loan fund. Following approval of customers' Energy Conservation Plans, funds will be made available to banks on a first-come first-served basis, based on the date and time loan requests are received by the State Energy Office. A waiting list will be established if funds are not immediately available, and loans will be processed from the waiting list in the order they were received.

Notifying Banks and Treasurer's Office of Approval

Upon approval of customer's Energy Conservation Plan, the State Energy Office will notify Partner Bank and the Treasurer's Office for each approved borrower.

Reimbursing Treasurer's Office for Administrative and Other Costs

Upon receipt of quarterly invoices from the Treasurer's Office for agreed-upon costs, the KCC will provide payment within 30 days.

4.5 Coordinating with Partner Banks on Promotion

The State Energy Office will coordinate closely with Partner Banks (and Partner Utilities) on the marketing and promotion of the Efficiency Kansas loan program. The State Energy Office's marketing campaign will highlight Partner Banks, while lightly marketing the state's oversight role in operating Efficiency Kansas.

The State Energy Office will involve interested Partner Banks (and Partner Utilities) in the development of the campaign. Marketing materials will be developed that can be customized for use by Partner Banks (and Partner Utilities).

Branding/Co-branding

Banks will be expected to include the Efficiency Kansas name and brand, along with their own name and brand, in all communications related to the revolving loan program. The relationship between the bank and the Efficiency Kansas revolving loan program will be expressed as a partnership.

Section 5: Glossary

Audit Report: The Audit Report is the document that the auditor provides to the customer, which details the results of the energy audit. This report includes technical information about the building's existing condition and also includes the Energy Conservation Plan.

Energy Conservation Plan: This plan contains the auditor's detailed recommendations for improving the energy efficiency of the building. It gives the customer the detailed specifications for all recommended improvements, which the customer will use to get final bids from contractors.

Meter-based Energy Efficiency Programs: These are utility-sponsored programs, in which the obligation to repay the costs of energy efficiency projects is assigned to the premise—that is, the utility meter—and survives changes in ownership and/or tenancy. These repayment costs are considered regular utility service.

Simple Payback: Simple Payback indicates how quickly the energy and dollar savings resulting from the project will "pay back" the cost of all improvements. Simple Payback is calculated by dividing the total cost of each project by the estimated annual savings resulting from all improvements. For an example, see Appendix 1.

Appendix 1: Efficiency Kansas Cost-effectiveness Calculations

Utility Track

To calculate the Program Charge for a full 15-year term:

$$\frac{\text{Installed Cost} + \$360 \text{ SEO fee} + (\text{Monthly Utility fee} \times 180)}{180} = \text{Program Charge}$$

To determine if Program Charge is ≤ 90% of Annual Savings:

$$\frac{\text{Annual Projected Savings} \times 0.9}{12} = \text{Maximum Amount of Program Charge}$$

To determine if Simple Payback is within 15 years:

$$\frac{\text{Installed Cost} + \$360 \text{ SEO fee} + (\text{Monthly Utility fee} \times 180)}{\text{Annual Projected Savings}} = \text{Simple Payback}$$

To find the shortest possible payback term:

$$\frac{\text{Annual Projected Savings} \times 0.9}{12} = \text{Program Charge for Shortest Payback Term}$$

$$\frac{\text{Installed Cost}}{\text{Monthly Program Charge} - \text{Monthly SEO fee} - \text{Monthly Utility fee}} = \text{Minimum \# of Payments}$$

Bank Track

To determine if Simple Payback is within the term of the loan, first calculate monthly projected savings:

$$\frac{\text{Annual Projected Savings}}{12} = \text{Monthly Projected Savings}$$

The Monthly Projected Savings will provide Partner Banks with information they need to determine term of loan with borrower:

$$\text{Monthly Projected Savings} \geq \text{Monthly Loan Payment (includes interest + SEO monthly fee)}$$

Appendix 2: Recommended Questions for Client Interview

Client Questionaire									
							Date:		
Name:									
Address:									
Auditor:									
How long have you lived at this address?									
Have you made any changes to the structure?					Yes No				
Are you in the process of remodeling or plan to remodel any portion of the home in the near future?									Yes No
Are any part of your ceilings, walls or floors in complete or in need of repair?									
Are some rooms colder than others?				Yes No					
Have your water pipes ever frozen?				Yes No					
Are there drafty areas in the house?				Yes No		Where?			
Do you have any roof leaks?				Yes No					
Do you have any foundation problems?				Yes No					
Are there any broken or leaking water or sewer lines?						Yes No			
Does water leak/stand in the basement/crawlspace?						Yes No			
If mobile home - is the underbelly free of debris and/or standing water?							Yes No		
Does ice form on your windows in the winter?					Yes No		Which ones?		
Have you noticed mold/mildew growing on windows, walls or or in corners?							Yes No		
Do you have ventilation fans at water locations?					Yes No	Do you use them?		Yes No	
Do you use your attic for storage?					Yes No				
Are any utilities turned off?					Yes No				
Do you close off any rooms in the house?				Yes No	Which ones?			Why?	
How many smokers live in the house?									
How many pets in the house?				Aquariums?		Size?			
Do you use your cookstove for heat?				Yes No					
Do you have any unvented space heaters in the house?					Yes No				
Do you keep kerosene, gasoline, paint thinner, etc. in the house?						Yes No	Where?		
Do you have a fireplace?			Yes No		Do you use it?		Yes No		
Does your furnace work?			Yes No						
What temp do you set your thermostat at in the winter?						Summer?			
Does your furnace produceany unusual noises or smells?					Yes No				
How often do you change the furnace filter?									
Do all registers deliver heat?				Yes No					
Do you have any disconnected ductwork?				Yes No					
Do you have any registers intentionally closed off?					Yes No				
What type of cooling system do you have?							Does it work?		Yes No

Appendix 3: Sample Site Data Collection Form

Site Data Collection

Created for use with REM/Rate REM Design

Building Name Owners Name Property Address City ______ State ______ Zip ______ Phone:	Builders Name Model/Name/No. Development Name Phone:	Area of Cond. Space ______ Zone 1 2 3 4 "N" ______ Volume of Cond. Space ______ No. Stories ______ House Type ______ Wind Well-sheid Norm Exp Level type ______ ACH50 ______ Floors on & above grade ______ NACH ______ No. Bedrooms ______ BTL ______ No. Occupants ______ CFM 50 ______

Foundation Type:	Type	Length	Height	↑ grade	↓ grade	Location	Slab Floors	type	area	Depth	perimeter	Exp. Perimeter
Name							Name					

Frame Floor	Area	Type	Location	Rim & Band Joists	Area	Cont. Ins. R	Cavity R	Insul ."	Joist oc	Location
Name				Name						

Above Grade Walls	Type	Area	Ext. Color	Location	Windows/Glass		Area	W shade	S shade	Oriented	Wall Assign
Name					Name	Type					

Ceilings	Type	Area	Rad Bar?	Ext.color	Doors	Opaque sf	Type	Wall assinment
Name					Name			

Skylight? Y N Type: P /12 Area: W. shade: S. shade: Orientation: Ceiling assign.:

Space Heating SB therm? Y N Brand ______ Model # ______ Input ______ Output ______ AFUE-COP-HSPF ______ Fuel type	**Space Heating** SB therm? Y N Brand ______ Model # ______ Input ______ Output ______ AFUE-COP-HSPF ______ Fuel type	**Space Cooling** Brand ______ Model # ______ Size ______ SEER - EER - COP ______ Ventilation: Nat WHF	**Space Cooling** Brand ______ Model # ______ Size ______ SEER - EER - COP ______ Ventilation: Natural Whole House Fan

Oven Fuel **Dryer Fuel** **Drywall thickness**

Water Heating
Brand ______ Gallons ______ Added Insul R- ______
Model # EF Location

Ducts:	Name	type	Location	Area	Added R	*Measured duct leakage :*	
						Supply	*Return*

Appendix 4: Unvented Heater Removal Agreement

Date: ____________________

Buildings heated by unvented space heaters are considered unsafe and shall not have air sealing or building tightness measures applied *unless* the heaters are removed from the premises, vented to the outside, or replaced with an appropriate heating unit.

This home has an unvented heater and the homeowner/tenant has been informed of the hazards associated with these types of heating units.

I, the undersigned, have been informed and agree to have the heater removed from the premises, or permanently vented to the outside prior to any air sealing or building tightness measures being applied to the building.

____________________________________ ____________________

Client Signature Date

Unvented Heater Removal Refusal

I, the undersigned, have been informed and do not agree to have the heater removed from the premises, or permanently vented to the outside prior to any air sealing or building tightness measures being applied to the building. I understand Efficiency Kansas funding may not be available for upgrades as outlined in the Efficiency Conservation Plan unless the heater is permanently vented to the outside or removed from the premises.

____________________________________ ____________________

Client Signature Date

No Existing Condition

I, the auditor, declare there is not an unvented heater on the premises.

____________________________________ ____________________

Auditor Signature Date

Appendix 5: Mechanical Testing Forms

The forms listed on the following pages are recommended for use by auditors when performing energy audits as part of the Efficiency Kansas loan program. These forms include:

- Instrumented Heating System Inspection: Form "F" Forced Air Units
- Instrumented Heating System Inspection: Form "G" Gravity Units
- Mid/High-Efficiency Furnace Jobsite Information Sheet – Form "H"
- Instrumented Heating System Inspection: Form "S" Console Heater, Floor and Wall Furnaces
- Instrumented Heating System Inspection: Form "W" Domestic Water Heaters
- Instrumented Heating System Inspection: Form "M" Mobile Home Units

Copies of the forms (as PDFs) can be downloaded from the Efficiency Kansas web site (www.efficiencykansas.com).

EFFICIENCY KANSAS INSTRUMENTED HEATING SYSTEM INSPECTION
FORM "F" Forced Air Units

Audit Company
Job Number: ____________________
Auditor: ____________________

Date:
Reinspection Date: ____________________
☐ This test is on the original unit.
☐ This test is on the replacement unit.

Furnace Information: ____________________ Mfg. ____________________ Model Number

Input Btu ____________________ Output Btu ____________________ Fuse Size/Type

Type of Heating Units: ☐ Upflow ☐ Downflow ☐ Horizontal ☐ A/C coil present
Fuel Type: ☐ Nat. gas ☐ LP ☐ Fuel Oil ☐ Elec. # of elements: ____

Precleaning Required? ☐ Yes ☐ No

*Turn Thermostat Up
Is furnace in operating condition? ☐ Yes ☐ No; If "no", describe action on page 3.
Number of Registers: __________ Supply __________ Return __________
Adequate Delivery at supply and return registers? ☐ Yes ☐ No

*Turn Thermostat Down
Location of Heating Unit: ____________________ [1]Enclosed Space? ☐ Yes ☐ No

If unit is located in **"enclosed space"**, how does it get air for combustion? ____________________
If there is **inadequate combustion air**, how/where will it be installed? ____________________
Gas Valve Control System: ☐ 24 Volt ☐ Mill volt ☐ Other: ____________________

Anticipator: Set Point Amps: ____________________ Measured Amps: ____________________
Reset to: ____________________ Manufacturer Spec. Amps: ____________________

* Conduct Heat Exchanger Test
* Turn gas valve to "off" position
* Plug heat exchanger openings
* Turn on furnace fan

Number of Heat Exchangers:
Smoke Pattern: ________ ________ ________ ________ ________ ________
Hole in Exchanger: ☐ Yes ☐ No Comments: ____________________
Heat Exchanger Clean ☐ Yes ☐ No *Cleaned?* ☐ Yes ☐ No

*Turn off furnace fan
*Remove Heat Exchanger Plugs

Gas Leaks: ☐ Yes ☐ No Comments: ____________________
Wiring Problems: ☐ Yes ☐ No Comments: ____________________
Scorch/Burn Marks: ☐ Yes ☐ No Comments: ____________________
Draft Hood Clean: ☐ Yes ☐ No ☐ N/A Cleaned? ☐ Yes ☐ No
Vent Type O.K.: ☐ Yes ☐ No Comments: ____________________
Vent Pitched: ☐ Yes ☐ No Comments: ____________________
Vent/Chimney: Condition O.K. ☐ Yes ☐ No Comments: ____________________

Pilot Assembly Clean: ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No Replaced? ☐ Yes ☐ No
Burner(s) Clean: ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No

* Drill holes in vent, supply and return duct
* Insert thermometer in supply and return duck
* Turn gas valve to **pilot** and relight pilot
* Turn gas valve **on**
* Turn thermostat up

START 5-MINUTE FURNACE TEST

	Initial		Retest	
Fan "ON" Set Point Supply Temperature:	________	°F	________	°F
Fan "ON" Set Time:	________	Seconds	________	Seconds
Measured Fan ON Temperature:	________	°F	________	°F
Location Temperature was taken:	____________________			

Heat Rise at 5 minutes:	Supply – Return		Supply – Return	
	______ – ______ = ______		______ – ______ = ______	
Manufacturer Heat Rise Specifications:	= ________	°F	= ________	°F

Carbon Monoxide in the vent:		PPM	PPM	
Draft	________	In. w.g.	> 800	.005" w.g.
=O.A. Temperature	________	°F	300-800	.01" w.g.
Induced Draft ☐ Yes ☐ No			<300	.02" w.g.

Spillage at Draft Hood: ☐ Yes ☐ No ☐ N/A

*Turn thermostat down

	Initial		Retest	
Fan "OFF" Set Point Supply Temperature:	________	°F	________	°F
Fan "OFF" Set Time:	________	Seconds	________	Seconds
Measured Fan OFF Temperature:	________	°F	________	°F

*Turn circuit breaker "off" or remove fuse

Duck Work Condition: ☐ O.K. ☐ Leaky ☐ Disconnected ☐ Sealed ☐ Reconnected

Filter Clean ☐ Yes ☐ No

Replaced Filter ☐ Yes ☐ No

Filter Size ____________ *Width* *X* ____________ *Height*

Installed Filter Rack and Filter ☐ Yes ☐ No

Blower Clean ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No

Belt: ☐ Yes ☐ N/A

Tension O.K. ☐ Yes ☐ No

Condition O.K. ☐ Yes ☐ No

Size ____ Inches

Motor Information	________	RPM	________	HP
	________	Amp-nameplate		
	________	Amp-measured	________	*Amp-measured*
Motor Wiring	________	to ________	________	to ________
(Record connections	________	to ________	________	to ________
before disconnection)	________	to ________	________	to ________

A/C Coil Clean ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No

*Turn circuit breaker "on"

*START LIGHT LIMIT TEST

	Initial		Retest	
High Limit Set Point	________	°F	________	°F
Supply Temperature Gas Valve- "OFF"	________	°F	________	°F

* Turn circuit breaker "off"
* Reassemble and connect blower
* Adjust motor speed (or time)/motor belt drive, if heat rise is over 80° or does not comply with/manufacture specifications
* Adjust fan "off" temperature to 90°
* Turn circuit breaker "on"
* Redo test to get desired fan "on"/"off" and heat rise and record new readings
* Tape and plug holes in return, supply, and vent
* Cycle the furnace

OWNER/CONTRACTOR REPAIR ITEMS

Owner	Contractor	Description of Repairs	Verified Complete

POST COMPLETION SAFETY TEST

* Close exterior windows and doors
* Turn Thermostat up
* START FINAL DRAFT AND CARBON MONOXIDE TEST

Draft at Startup	________	in. w.g.
Draft at 5 minutes	________	in. w.g.
Carbon Monoxide in Vent	________	**PPM**

* Turn Thermostat down
* Install blower door and zero gauges at 20 pa
* Turn all exhaust fans (including driers and range hoods) "on"

Gauge Reading ________ ***Pa ÷ 248 =(A)*** ________ ***In. w.g.***

If "A" is less than the draft reading at 5 minutes, the O.K.
If "A" is more than the draft reading at 5 minutes, then additional combustion air is required

* Return House to Original Condition

COMMENTS:

1. Divide the total input Btu of all appliances in the space divide by 20 to determine the required volume.

[________ Input Btu ÷ 20 = ________ (Required volume in feet^3)] ________

Form "F" — Page 3

EFFICIENCY KANSAS INSTRUMENTED HEATING SYSTEM INSPECTION
FORM "G" Gravity Units

Audit Company ____________________ Date: ____________
Job Number: ____________________ Re-inspection Date: ____________
Auditor: ____________________
☐ This test is on the original unit.
☐ This test is on the replacement unit.

Furnace Information: ____________ Mfg. ____________ Model Number

Input Btu ____________ *Output Btu* ____________ Fuse Size/Type

Fuel Type: ☐ Natural gas ☐ LP ☐ Fuel Oil
Precleaning Required? ☐ Yes ☐ No

*Turn Thermostat Up

Is furnace in operating condition? ☐ Yes ☐ No; If "no", describe action on page 3.
Number of Registers: ________ Supply ________ Return ________

*Turn Thermostat Down

Location of Heating Unit: ____________ [1]Enclosed Space? ☐ Yes ☐ No
If the unit is located in "**enclosed space**", how does it get air for combustion? ____________
If there is **inadequate combustion air**, how/where will it be installed? ____________

Gas Valve Control System: ☐ 24 Volt ☐ Mill volt ☐ Other: ____________

Anticipator: Set Point Amps: ____________ Measured Amps: ____________
Reset to: ____________ Manufacturer Spec. Amps: ____________

*Conduct Heat Exchanger Test

Hole in Exchanger:	☐ Yes	☐ No	Comments:	____________
Heat Exchanger Clean	☐ Yes	☐ No	Cleaned?	☐ Yes ☐ No
Gas Leaks:	☐ Yes	☐ No	Comments:	____________
Wiring Problems:	☐ Yes	☐ No	Comments:	____________
Scorch/Burn Marks:	☐ Yes	☐ No	Comments:	____________
Draft Hood Clean:	☐ Yes	☐ No	☐ N/A	Cleaned? ☐ Yes ☐ No
Vent Type O.K.:	☐ Yes	☐ No	Comments:	____________
Vent Pitched:	☐ Yes	☐ No	Comments:	____________
Vent/Chimney: Condition O.K.	☐ Yes	☐ No	Comments:	____________

Pilot Assembly Clean: ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No Replaced? ☐ Yes ☐ No
Burner(s) Clean: ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No

* Drill holes in vent, supply and return duct
* Insert thermometer in supply and return duck
* Turn gas valve to **pilot** and relight pilot
* Turn gas valve **on**
* Turn thermostat up
* START 5-MINUTE FURNACE TEST

	Initial		Reset	
Measured Supply Temperature @ 5 Minutes	________	°F	________	°F
Location Temperature was taken:	________		________	
Carbon Monoxide in the vent:	________	PPM	________	PPM
Draft	________	In. w.g.	________	In. w.g.
=O.A. Temperature	________	°F	________	°F

Spillage at Draft Hood: ☐ Yes ☐ No Comments: ____________

Duck Work Condition: ☐ O.K. ☐ Leaky ☐ Disconnected ☐ Sealed ☐ Reconnected

OWNER/CONTRACTOR REPAIR ITEMS

Owner	Contractor	Description of Repairs	Verified Complete
______	______	______	______
______	______	______	______
______	______	______	______
______	______	______	______

POST COMPLETION SAFETY TEST

* Close exterior windows and doors
* Turn Thermostat up
* START FINAL DRAFT AND CARBON MONOXIDE TEST

Draft at Startup ______ in. w.g.

Draft at 5 minutes ______ in. w.g.

Carbon Monoxide in Vent ______ PPM

* Turn Thermostat down
* Install blower door and zero gauges at 20 pa
* Turn all exhaust fans (including driers and range hoods) "on"

Gauge Reading ______ *Pa ÷ 248 =(A)* ______ *In. w.g.*

If "A" is less than the draft reading at 5 minutes, the O.K.
If "A" is more than the draft reading at 5 minutes, then additional combustion air is required
* Return House to Original Condition

COMMENTS:

1. Divide the total input Btu of all appliances in the space by 20 to determine the required volume.
[______ Input Btu ÷ 20 = ______ (Required volume in feet^3)]

Form "G" — Page 2

EFFICIENCY KANSAS MID/HIGH-EFFICIENCY FURNACE JOBSITE INFORMATION SHEET — FORM "H"

Client Information: Job Number ______________ Date: ______________

Name: ______________ Auditor: ______________

Street: ______________ Furnace Data: Manufacture: ______________

City: ______________ Zip: ______________ Model Number: ______________

Phone: ______________ Serial Number: ______________

Type: ☐ Upflow ☐ Downflow ☐ Horizontal Fuel Type: ☐ Nat. gas ☐ LP ☐ Fuel Oil

☐ 80% AFUE ☐ 90% AFUE ☐ A/C coil present

Precleaning Required? ☐ Yes ☐ No

▶Turn Thermostat Up

Is furnace in operating condition? ☐ Yes ☐ No: *If "no", describe action on back page.*

Number of Registers: ______________ Supply ______________ Return ______________

Adequate Delivery at supply and return registers? ☐ Yes ☐ No Comments: ______________

▶Turn Thermostat Down

Location of Heating Unit: ______________ Enclosed Space? ☐ Yes ☐ No

If the unit is located in "enclosed space" how does it get air for combustion? ______________

If there is inadequate combustion air, how/where will it be installed? ______________

Sealed Combustion ☐ Yes ☐ No

Anticipator: Set Point Amps: ______________ Measured Amps: ______________

Reset to: ______________ Manufacturer Spec. Amps: ______________

▶Conduct Heat Exchanger Test (if accessible, and possible)

- Observe flame at fan ON (note any distortion or movement)
- Inject traced gas in plenum (may require removal of cover plate)
- Measure for tracer gas in plenum (may require drilling of access hole)

Evidence of hole in heat exchanger? ☐ Yes ☐ No Comments: ______________

Is Heat Exchanger Clean? ☐ *Yes* ☐ *No* *Cleaned?* ☐ *Yes* ☐ *No*

Gas Leaks:	☐ Yes	☐ No	Comments: ______________
Wiring Problems:	☐ Yes	☐ No	Comments: ______________
Scorch/Burn Marks:	☐ Yes	☐ No	Comments: ______________
Draft Hood Clean:	☐ Yes	☐ No	Comments: ______________
Vent Type O.K.:	☐ Yes	☐ No	Comments: ______________
Vent Pitched:	☐ Yes	☐ No	Comments: ______________
PVC Vent Terminus OK:	☐ Yes	☐ No	Comments: ______________
Vent/Chimney OK:	☐ Yes	☐ No	Comments: ______________

Pilot Assembly Clean: ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No Replaced? ☐ Yes ☐ No

Electronic Ignition: ☐ Yes ☐ No Burner(s) clean: ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No

Fired Sequence Test:

- ▶ Drill holes in exhaust vent, supply and return plenum (duct)
- ▶ Insert thermometer in supply and return plenum (duct)
- ▶ **Turn thermostat up**
- ▶ START FIVE MINUTE FURNACE TEST

Fan "ON"
Temperature: ____________ °F   Fan ON Time ______________ Seconds

Location Temperature was recorded: ______________________________

Heat Rise at 5 minutes: Supply – Return
____________ — ____________ = ____________ °F

Manufacturer Heat Rise Specifications: ____________ — ____________ = ____________ °F

Carbon monoxide in the vent ____________ PPM

▶*Turn thermostat down*

Draft: Test 80% AFUE vent/chimney immediately after burn cycle is completed ____________ In. w.g.

Measured Fan OFF Temperature: ____________ °F

Condition of ducts: ☐ O.K. ☐ Leaky ☐ Disconnected ☐ Sealed ☐ Reconnected

Filter Clean ☐ Yes ☐ No

Replaced Filter ☐ Yes ☐ No

Filter Size ____________ *Width* *X* ____________ *Height*

Installed Filter Rack and Filter ☐ Yes ☐ No

Blower Clean ☐ Yes ☐ No   Cleaned? ☐ Yes ☐ No

OWNER/CONTRACTOR REPAIR ITEMS

Owner	Contractor	Description of Repairs	Verified Complete

POST COMPLETION SAFETY TEST

* Close exterior windows and doors
* Turn Thermostat up
* START FINAL DRAFT AND CARBON MONOXIDE TEST

Draft at Startup	____________	in. w.g.
Draft at 5 minutes	____________	in. w.g.
Carbon Monoxide in Vent	____________	**PPM**

* Turn Thermostat down
* Install blower door and zero gauges at 20 pa
* Turn all exhaust fans (including driers and range hoods) "on"

Gauge Reading ____________________ ***Pa ÷ 248 =(A)*** ____________________ ***In. w.g.***

If "A" is less than the draft reading at 5 minutes, the O.K.
If "A" is more than the draft reading at 5 minutes, then additional combustion air is required

* Return House to Original Condition

COMMENTS:

1. Divide the total input Btu of all appliances in the space by 20 to determine the required volume.

[____________ Input Btu ÷ 20 = ____________ (Required volume in feet^3)] ____________________

Form "H" – Page 3

EFFICIENCY KANSAS INSTRUMENTED HEATING SYSTEM INSPECTION
FORM "S" Console Heater, Floor and Wall Furnaces

Audit Company: ______________________ Date: ______________
Job Number: ______________________ Re-inspection Date: ______________
Auditor: ______________________
☐ This test is on the original unit.
☐ This test is on the replacement unit.

Furnace Information: ______________ Mfg. ______________ Model Number
Input Btu
______________ ______________ Fuse Size/Type

Type of Units: ☐ Console ☐ Floor Furnace ☐ Wall Furnace | **Fuel Type:** ☐ Nat. gas ☐ LP ☐ Fuel Oil ☐ Elec. # Of elements: _____

Precleaning Required? ☐ Yes ☐ No
*Turn Thermostat Up

Is furnace in operating condition? ☐ Yes ☐ No; If "no", describe action on page 3.

Number of Registers: __________ Supply ______________ Return ______________

*Turn Thermostat Down

Location of Heating Unit: ______________ [1]Enclosed Space? ☐ Yes ☐ No
If the unit is located in "**enclosed space**", how does it get air for combustion? ______________
If there is **inadequate combustion air**, how/where will it be installed? ______________

Gas Valve Control System: ☐ 24 Volt ☐ Mill volt ☐ Other: ______________

Anticipator: Set Point Amps: ______________ Measured Amps: ______________
Reset to: ______________ Manufacturer Spec. Amps: ________

*Conduct Heat Exchanger Test

Hole in Exchanger:	☐ Yes	☐ No	Comments:	
Heat Exchanger Clean	☐ Yes	☐ No	Cleaned?	☐ Yes ☐ No
Gas Leaks:	☐ Yes	☐ No	Comments:	
Wiring Problems:	☐ Yes	☐ No	Comments:	
Scorch/Burn Marks:	☐ Yes	☐ No	Comments:	
Vent Type O.K.:	☐ Yes	☐ No	Comments:	
Draft Hood Clean:	☐ Yes	☐ No	☐ N/A	Cleaned? ☐ Yes ☐ No
Vent Type O.K.:	☐ Yes	☐ No	Comments:	
Vent Pitched:	☐ Yes	☐ No	Comments:	
Vent/Chimney: Condition O.K.:	☐ Yes	☐ No	Comments:	
Pilot Assembly Clean:	☐ Yes	☐ No	Cleaned? ☐ Yes ☐ No	Replaced? ☐ Yes ☐ No
Burner(s) Clean:	☐ Yes	☐ No	Cleaned? ☐ Yes ☐ No	

* Drill holes in vent, supply and return duct
* Insert thermometer in supply and return duck
* Turn gas valve to **pilot** and relight pilot
* Turn gas valve **on**
* Turn thermostat up
* START 5-MINUTE FURNACE TEST

	Initial		Reset	
Measured Supply Temperature @ 5 Minutes	________	°F	________	°F
Location Temperature was taken:	________		________	
Carbon Monoxide in the vent:	________	PPM	________	PPM
Draft	________	In. w.g.	________	In. w.g.
O.A. Temperature	________	°F	________	°F

Spillage at Draft Hood: ☐ Yes ☐ No Comments: ______________
Duck Work Condition: ☐ O.K. ☐ Leaky ☐ Disconnected ☐ Sealed ☐ Reconnected

Owner	Contractor	Description of Repairs	Verified Complete
________	________	________	________
________	________	________	________
________	________	________	________
________	________	________	________

POST COMPLETION SAFETY TEST

* Close exterior windows and doors
* Turn Thermostat up
* START FINAL DRAFT AND CARBON MONOXIDE TEST

Draft at Startup	________	in. w.g.
Draft at 5 minutes	________	in. w.g.
Carbon Monoxide in Vent	________	PPM

* Turn Thermostat down
* Install blower door and zero gauges at 20 pa
* Turn all exhaust fans (including driers and range hoods) "on"

Gauge Reading	________	Pa ÷ 248 =(A)	________	In. w.g.

If "A" is less than the draft reading at 5 minutes, the O.K.
If "A" is more than the draft reading at 5 minutes, then additional combustion air is required

* Return House to Original Condition

Form "S" – Page 2

EFFICIENCY KANSAS INSTRUMENTED HEATING SYSTEM INSPECTION
FORM "W" Domestic Water Heaters

Auditor Company: ____________________ Date: ____________
Job Number: ____________________ Reinspection Date: ____________
Auditor: ____________________ ☐ This test is on the original unit.
Manufacturer:: ☐ This test is on the replacement unit.

Model Number:	Energy Factor (EF):
Size: Gallons	Input Btu's:

Fuel Type: ☐ Natural gas ☐ LP ☐ Fuel Oil ☐ Electric > Number of elements _____
Location of DWH: ____________ [1]Enclosed Space? ☐ Yes ☐ No
If the unit is located in "**enclosed space**", how does it get air for combustion? ____________
If there is **inadequate combustion air**, how/where will it be installed? ____________

Hole in Exchanger:	☐ Yes	☐ No	Comments:
Spillage at Draft Hood:	☐ Yes	☐ No	Comments:
Gas Leaks:	☐ Yes	☐ No	Comments:
Wiring Problems:	☐ Yes	☐ No	Comments:
Scorch/Burn Marks:	☐ Yes	☐ No	Comments:
Draft Hood Clean:	☐ Yes	☐ No	☐ N/A Cleaned? ☐ Yes ☐ No
Vent Type O.K.:	☐ Yes	☐ No	Comments:
Vent Pitched:	☐ Yes	☐ No	Comments:
Vent/Chimney: Condition O.K.	☐ Yes	☐ No	Comments:

Pilot Assembly Clean: ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No Replaced? ☐ Yes ☐ No
Burner(s) Clean: ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No
Hot water temperature ______ °F
Reset water temperature to 120° F: ☐ Yes ☐ No Reset to: ______ °F

	Initial – Pre	Final Inspection
Location Temperature was taken:		
Carbon Monoxide in the vent:	PPM	PPM
Draft	In. w.g.	In. w.g.
O.A. Temperature	°F	°F

OWNER/CONTRACTOR REPAIR ITEMS

Owner	Contractor	Description of Repairs	Verified Complete

1. Divide the total input Btu of all appliances in the space by 20 to determine the required volume.

[____________ Input Btu ÷ 20 = ____________ (Required volume in feet^3)]

EFFICIENCY KANSAS INSTRUMENTED HEATING SYSTEM INSPECTION
FORM "M" — Mobile Home Units

Audit Co: ______________________ Date: ______________
Job Number: ______________ Reinspection Date: ______________
Auditor ______________ ☐ This test is on the original unit.
☐ This test is on the replacement unit.

Furnace Information: ______________ **Mfg.** ______________ **Model Number**
Output Btu

Input Btu ______________ ______________ **Fuse Size/Type**

Type of Heating Units: ☐ Downflow ☐ Upflow **Fuel Type:** ☐ Nat. gas ☐ LP
☐ =>80% AFUE ☐ A/C coil present ☐ Fuel Oil ☐ Elec. # Of elements: _____

Precleaning Required? ☐ **Yes** ☐ **No**

*Turn Thermostat Up

Is furnace in operating condition? ☐ Yes ☐ No; If "no", describe action on page 3.

Number of Registers: ________ Supply ________ Return ________

Adequate Delivery at supply and return registers? ☐ Yes ☐ No

***Turn Thermostat Down**

Location of Heating Unit: ______________

Combustion Air source: ☐ Double Vented ☐ Under Home

Gas Valve Control System: ☐ **24 Volt** ☐ **Mill volt** ☐ **Other:** ______________

Anticipator: **Set Point Amps:** ______________ **Measured Amps:** ______________
Reset to: ______________ **Manufacturer Spec. Amps:** ______________

Hole in Exchanger: ☐ Yes ☐ No Comments: ______________
Heat Exchanger Clean ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No

Gas Leaks: ☐ Yes ☐ No Comments: ______________
Wiring Problems: ☐ Yes ☐ No Comments: ______________
Scorch/Burn Marks: ☐ Yes ☐ No Comments: ______________
Vent Type O.K.: ☐ Yes ☐ No Comments: ______________
Roof Jack: Condition O.K. ☐ Yes ☐ No Comments:

Pilot Assembly Clean: ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No Replaced? ☐ Yes ☐ No
Burner(s) Clean: ☐ Yes ☐ No Cleaned? ☐ Yes ☐ No

* Insert one thermometer in nearest supply register and one in the return air opening or door
* Turn thermostat up
* START 5 MINUTE TEST

	Initial		Retest	
Fan "ON" Set Point Supply Temperature:	________	°F	________	°F
Fan "ON" Set Time:	________	Seconds	________	Seconds
Measured Fan ON Temperature:	________	°F	________	°F
Location Temperature was taken:	________		________	

Heat Rise at 5 minutes: Supply – Return Supply – Return
_______ – _______ = _______ _______ – _______ = _______

Manufacturer Heat Rise Specifications: = ________ °F = ________ °F

***Turn Thermostat Down**

Fan "OFF" Set Point Supply Temperature:	________	°F	________	°F
Fan "OFF" Set Time:	________	Seconds	________	Seconds
Measured Fan OFF Temperature:	________	°F	________	°F

	Initial			Retest	
*Turn circuit breaker "off" or remove fuse					
Duck Work Condition:	☐ O.K.	☐ Leaky	☐ Disconnected	☐ Sealed	☐ Reconnected
Filter Clean	☐ Yes	☐ No			
Replaced Filter	☐ Yes	☐ No			
Filter Size	________	*Width*	***X***	________	*Height*
Installed Filter Rack and Filter	☐ Yes	☐ No			
Blower Clean	☐ Yes	☐ No	Cleaned?	☐ Yes	☐ No
Motor Information	________	RPM	________	HP	
	________	Amp-nameplate			
	________	Amp-measured		________	*Amp-measured*
Motor Wiring	________	to	________	________ to	________
(Record connections	________	to	________	________ to	________
before disconnection)	________	to	________	________ to	________
A/C Coil Clean	☐ Yes	☐ No	Cleaned?	☐ Yes	☐ No
*Turn circuit breaker "on" *START LIGHT LIMIT TEST					
High Limit Set Point	________	°F		________	°F
Supply Temperature Gas Valve- "OFF"	________	°F		________	°F

* Turn circuit breaker "off"
* Reassemble and connect blower
* Adjust motor speed (or time)/motor belt drive, if heat rise is over 80° or does not comply with/manufacture specifications
* Adjust fan "off" temperature to 90°
* Turn circuit breaker "on"
* Redo test to get desired fan "on"/"off" and heat rise and record new readings
* Cycle the furnace

OWNER/CONTRACTOR REPAIR ITEMS

Owner	Contractor	Description of Repairs	Verified Complete

COMMENTS:

Appendix 6: Energy Savings Report

Auditor Information

Name of Auditor: ______________________________

Company: ______________________________

Structure Information

Address of structure being audited ____________________________

Total square feet of space ______________________

Building Type: __Residential __Commercial __Industrial

Fuel Savings Information

Annual reduction of natural gas (MCF) ____

Annual reduction of electricity (kWh) ____

Annual demand reduction (kW) ____

Annual reduction of fuel oil (gallons) ____

Annual reduction of propane (gallons) ___

Annual reduction of Gasoline and Diesel Fuel (gallons) ____

Renewable Energy (if applicable)

Installed capacity of wind generation (kW) ____

Electricity generated from wind (kWh) ____

Installed capacity of solar photovoltaic (kW) ____

Electricity generated from solar photovoltaic (kWh) ____

Installed capacity of other renewable sources (kW) ____

Electricity generated from other renewable sources (kWh) ____

Appendix 7: Contractor Terms and Conditions

Contractor Name: ____

Contractor Address: ______________________________ **Phone Number:**________

Consumer Name: _______________ **Consumer Address:**___________________________

Terms and Conditions for Contractors Preparing Bids for Efficiency Kansas Loan Program

Contractors, please initial on the space provided after reading each condition.

I understand that the following are prerequisites for bidding:

______ **Bids must have itemized cost of materials to be used in the energy conservation plan.**

______ **Labor cost must be listed separately from materials.**

______ **When required in a particular jurisdiction, I must obtain all necessary building permits from the local authority for the work to be performed.**

______ All bids must state exactly what will be done, so the State Energy Office has documentation for accountability purposes.

______ All bids are to be based on the energy conservation plan provided by the auditor, and approved by the State Energy Office.

______ Material or labor costs are **NOT** paid in advance.

______ **No work shall begin until such time as the State Energy Office has approved the appropriate bid and you have received written notification of this approval.**

______ All work will be done in a professional manner and in accordance with industry standards.

______ If labor costs exceed $2,000, then all work shall comply with Davis Bacon prevailing wage statutes, and the reporting of same to the DOE.[6]

I understand if I am awarded the project that:

______ I shall only perform those items of work that are approved by the State Energy Office. I shall not perform any extra work requested by the homeowner. Without prior approval, the State Energy Office will not be responsible for the additional costs.

______ Before beginning any repairs, I will ensure that the customer has been informed of the materials and supplies that will be used and has agreed to their use.

______ Upon my completion of the work, the auditor and customer will inspect and approved all work; payment may not be received until a Certificate of Project Completion is forwarded to the State Energy Office.

______ The State Energy Office does not process payments until the work is completed and approved by the auditor and the customer.

______ **I will warrant that my work is free from defects in material and workmanship for a period of one (1) year.** Upon notice of a material defect in the work within that period, I shall be responsible to perform any repairs, replacements, or corrections to the defective construction, at no cost to the State Energy Office, utility, or the homeowner, and within a reasonable period of time. Nevertheless, I shall not be responsible if: (1) my work has been modified, altered, defaced, or had repairs made or attempted by others; or (2) if the material defect was caused by an Act of God.

I have read and agree to the terms and conditions of the Efficiency Kansas Loan Program. I understand that any expenses exceeding what was approved by the State Energy Office, or expenses that exceed the maximum award of the program, will **not** be the responsibility of the State Energy Office.

______________________________ ___/___/___

Contractor Signature Date

[6] The State Energy Office is awaiting further guidance from the Department of Energy regarding Davis-Bacon requirements.

Appendix 8: Davis-Bacon Acknowledgment[7]

[7] The State Energy Office is awaiting further guidance from the Department of Energy on Davis Bacon requirements.

Appendix 9: Certificate of Project Completion

CUSTOMER: ____

ADDRESS: ____

____

____

AUDITOR ____

This is to certify that a final inspection of the above Project has been conducted jointly by the Auditor, the Customer and the Bank or Utility, and that the Parties have determined that the Project has been fully completed in accordance with the Audit Specifications submitted to Bank or Utility and approved by the State Energy Office.

The Customer accepts the project as being fully completed and assumes the responsibility for maintenance, custodial care and utilities for the premises.

AUDITOR

______________________ ______________________ Date __________
Printed Name Signature

CUSTOMER

______________________ ______________________ Date __________
Printed Name Signature

UTILITY/BANK

______________________ ______________________ Date __________
Printed Name Signature

Appendix 10: Utility Contact Form

Kansas Corporation Commission

Efficiency Kansas

UTILITY CONTACT INFORMATION

PLEASE COMPLETE & RETURN THIS FORM TO: Kansas Corporation Commission, State Energy Office, Attn: Efficiency Kansas Manager, 1300 SW Arrowhead Road, Suite 100, Topeka, KS 66604-4074

Utility Name: ______________________________

Home Office Address: ______________________________

Information Provided By: ______________________________

<u>CONTACT(S) FOR ENERGY EFFICIENCY PROGRAM</u>

Name: ______________________ *Title:* ______________________
Address: ______________________ *City, State, Zip:* ______________________
Phone: __________ *Fax:* __________ *Email:* ______________________

Name: ______________________ *Title:* ______________________
Address: ______________________ *City, State, Zip:* ______________________
Phone: __________ *Fax:* __________ *Email:* ______________________

<u>CONTACT(S) FOR ENERGY AUDIT CUSTOMER SUPPORT</u>

Name: ______________________ *Title:* ______________________
Address: ______________________ *City, State, Zip:* ______________________
Phone: __________ *Fax:* __________ *Email:* ______________________

Name: ______________________ *Title:* ______________________
Address: ______________________ *City, State, Zip:* ______________________
Phone: __________ *Fax:* __________ *Email:* ______________________

<u>CONTACT(S) FOR GENERAL ACCOUNTING & BALANCE CONFIRMATIONS</u>

Name: ______________________ *Title:* ______________________
Address: ______________________ *City, State, Zip:* ______________________
Phone: __________ *Fax:* __________ *Email:* ______________________

Name: ______________________ *Title:* ______________________
Address: ______________________ *City, State, Zip:* ______________________
Phone: __________ *Fax:* __________ *Email:* ______________________

BLS
1 2 5 YEARS
BUREAU OF LABOR STATISTICS
U.S. DEPARTMENT OF LABOR

NEWS RELEASE

Transmission of material in this release is embargoed until 8:30 a.m. (EDT) Friday, August 7, 2009

USDL-09-0908

Technical information:
Household data: (202) 691-6378 • CPSinfo@bls.gov • www.bls.gov/cps
Establishment data: (202) 691-6555 • CESinfo@bls.gov • www.bls.gov/ces

Media contact: (202) 691-5902 • PressOffice@bls.gov

THE EMPLOYMENT SITUATION – JULY 2009

Nonfarm payroll employment continued to decline in July (-247,000), and the **unemployment rate** was little changed at 9.4 percent, the U.S. Bureau of Labor Statistics reported today. The average monthly job loss for May through July (-331,000) was about half the average decline for November through April (-645,000). In July, job losses continued in many of the major industry sectors.

Chart 1. Unemployment rate, seasonally adjusted, July 2007 – July 2009

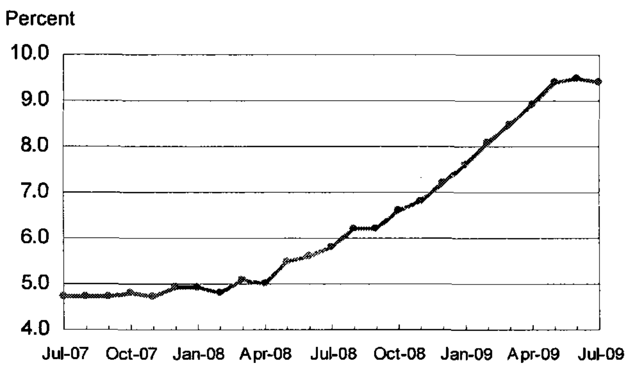
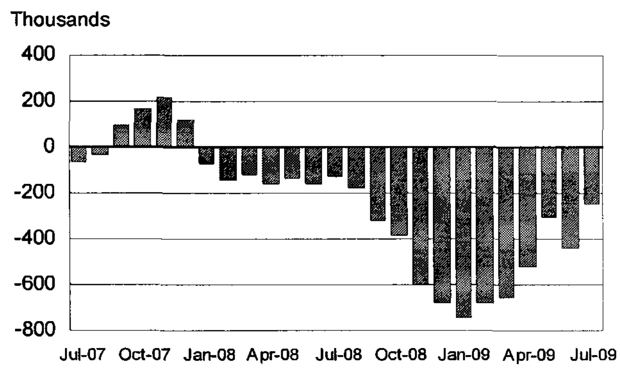


Chart 2. Nonfarm payroll employment over-the-month change, seasonally adjusted, July 2007 – July 2009



Household Survey Data

In July, the number of **unemployed persons** was 14.5 million. The **unemployment rate** was 9.4 percent, little changed for the second consecutive month. (See table A-1.)

Among the **major worker groups**, unemployment rates for adult men (9.8 percent), adult women (7.5 percent), teenagers (23.8 percent), whites (8.6 percent), blacks (14.5 percent), and Hispanics (12.3 percent) were little changed in July. The unemployment rate for Asians was 8.3 percent, not seasonally adjusted. (See tables A-1, A-2, and A-3.)

The number of **long-term unemployed** (those jobless for 27 weeks or more) rose by 584,000 over the month to 5.0 million. In July, 1 in 3 unemployed persons were jobless for 27 weeks or more. (See table A-9.)

The **civilian labor force participation rate** declined by 0.2 percentage point in July to 65.5 percent. The **employment-population ratio**, at 59.4 percent, was little changed over the month but has declined by 3.3 percentage points since the recession began in December 2007. (See table A-1.)

The number of persons working **part time for economic reasons** (sometimes referred to as involuntary part-time workers) was little changed in July at 8.8 million. The number of such workers rose sharply in the fall and winter but has been little changed for 4 consecutive months. (See table A-5.)

About 2.3 million persons were **marginally attached to the labor force** in July, 709,000 more than a year earlier. (The data are not seasonally adjusted.) These individuals, who were not in the labor force, wanted and were available for work and had looked for a job sometime in the prior 12 months. They were not counted as unemployed because they had not searched for work in the 4 weeks preceding the survey. (See table A-13.)

Among the marginally attached, there were 796,000 **discouraged workers** in July, up by 335,000 over the past 12 months. (The data are not seasonally adjusted.) Discouraged workers are persons not currently looking for work because they believe no jobs are available for them. The other 1.5 million persons marginally attached to the labor force in July had not searched for work in the 4 weeks preceding the survey for reasons such as school attendance or family responsibilities.

Establishment Survey Data

Total **nonfarm payroll employment** declined by 247,000 in July. From May to July, job losses averaged 331,000 per month, compared with losses averaging 645,000 per month from November to April. Since December 2007, payroll employment has fallen by 6.7 million. (See table B-1.)

Employment in **construction** declined by 76,000 in July, about in line with the average for the past 3 months (-73,000). Employment had decreased by 117,000 a month on average from November to April.

Manufacturing employment fell by 52,000 in July and has declined by 2.0 million since the recession began. In motor vehicles and parts, fewer workers than usual were laid off in July for seasonal retooling. As a result, the estimate of employment for the industry rose by 28,000 after seasonal adjustment. In large part, July's seasonally-adjusted increase reflects the fact that previous job cuts had been so extensive that there were fewer workers to lay off during the seasonal shutdown. Elsewhere in manufacturing, several industries continued to lose jobs in July, including machinery (-15,000) and fabricated metal products (-14,000).

In July, **retail trade** employment declined by 44,000. Job losses in the industry had averaged 27,000 per month over the prior 3 months. Employment in **wholesale trade** fell by 19,000 in July, with the majority of the decline occurring among durable goods wholesalers.

Employment in **professional and business services** continued to trend down in July (-38,000); the industry has shed 1.5 million jobs since the start of the recession. Within professional and business services, employment in the temporary help industry edged down in July. While temporary help has lost 844,000 jobs since the recession began, the declines have lessened substantially over the past 3 months.

Transportation and warehousing lost 22,000 jobs in July. Since May, the average monthly job loss was half the average monthly decline for November through April (-17,000 versus -34,000).

Financial activities employment continued to trend down in July (-13,000). The average monthly decline for this industry was 23,000 over the past 3 months compared with 46,000 per month from November through April. Since the start of the recession, the financial activities industry has lost 501,000 jobs. Employment in **information** declined by 16,000 in July, including losses in publishing and telecommunications.

Health care employment increased by 20,000 in July, about in line with the average monthly gain for the first half of this year but down from an average monthly increase of 30,000 during 2008. Employment in **leisure and hospitality** has been little changed over the past 3 months.

In July, the **average workweek** of production and nonsupervisory workers on private nonfarm payrolls edged up by 0.1 hour to 33.1 hours. The manufacturing workweek increased by 0.3 hour to 39.8 hours. Factory overtime was unchanged at 2.9 hours. (See table B-2.)

In July, **average hourly earnings** of production and nonsupervisory workers on private nonfarm payrolls rose by 3 cents, or 0.2 percent, to $18.56. Over the past 12 months, average hourly earnings have increased by 2.5 percent, while average weekly earnings have risen by only 1.0 percent due to declines in the average workweek. (See table B-3.)

The change in total nonfarm payroll employment for May was revised from -322,000 to -303,000, and the change for June was revised from -467,000 to -443,000.

The Employment Situation for August is scheduled to be released on Friday, September 4, 2009, at 8:30 a.m. (EDT).

Table A. Major indicators of labor market activity, seasonally adjusted
(Numbers in thousands)

Category	Quarterly averages		Monthly data			June-July change
	I 2009	II 2009	May 2009	June 2009	July 2009	
HOUSEHOLD DATA	Labor force status					
Civilian labor force	153,993	154,912	155,081	154,926	154,504	-422
Employment	141,578	140,591	140,570	140,196	140,041	-155
Unemployment	12,415	14,321	14,511	14,729	14,462	-267
Not in labor force	80,920	80,547	80,371	80,729	81,366	637
	Unemployment rates					
All workers	8.1	9.2	9.4	9.5	9.4	-0.1
Adult men	8.2	9.7	9.8	10.0	9.8	-.2
Adult women	6.7	7.4	7.5	7.6	7.5	-.1
Teenagers	21.3	22.7	22.7	24.0	23.8	-.2
White	7.4	8.4	8.6	8.7	8.6	-.1
Black or African American	13.1	14.9	14.9	14.7	14.5	-.2
Hispanic or Latino ethnicity	10.7	12.0	12.7	12.2	12.3	.1
ESTABLISHMENT DATA	Employment					
Nonfarm employment	133,662	p 132,131	132,178	p 131,735	p 131,488	p -247
Goods-producing [1]	19,826	p 19,037	19,041	p 18,818	p 18,690	p -128
Construction	6,590	p 6,300	6,310	p 6,224	p 6,148	p -76
Manufacturing	12,468	p 12,005	12,000	p 11,869	p 11,817	p -52
Service-providing [1]	113,835	p 113,094	113,137	p 112,917	p 112,798	p -119
Retail trade [2]	14,933	p 14,814	14,812	p 14,791	p 14,747	p -44
Professional and business service	17,048	p 16,730	16,756	p 16,650	p 16,612	p -38
Education and health services	19,138	p 19,214	19,215	p 19,252	p 19,269	p 17
Leisure and hospitality	13,235	p 13,180	13,195	p 13,177	p 13,186	p 9
Government	22,543	p 22,593	22,605	p 22,557	p 22,564	p 7
	Hours of work [3]					
Total private	33.2	p 33.1	33.1	p 33.0	p 33.1	p 0.1
Manufacturing	39.6	p 39.5	39.4	p 39.5	p 39.8	p .3
Overtime	2.7	p 2.8	2.8	p 2.9	p 2.9	p .0
	Indexes of aggregate weekly hours (2002=100) [3]					
Total private	101.7	p 99.7	99.8	p 99.1	p 99.1	p 0.0
	Earnings [3]					
Average hourly earnings, total private	$18.46	p $18.52	$18.53	p $18.53	p $18.56	p $0.03
Average weekly earnings, total private	613.60	p 612.39	613.34	p 611.49	p 614.34	p 2.85

[1] Includes other industries, not shown separately.
[2] Quarterly averages and the over-the-month change are calculated using unrounded data.
[3] Data relate to private production and nonsupervisory workers.
p = preliminary.

Frequently Asked Questions about Employment and Unemployment Estimates

Why are there two monthly measures of employment?

The household survey and establishment survey both produce sample-based estimates of employment and both have strengths and limitations. The establishment survey employment series has a smaller margin of error on the measurement of month-to-month change than the household survey because of its much larger sample size. An over-the-month employment change of 107,000 is statistically significant in the establishment survey, while the threshold for a statistically significant change in the household survey is about 400,000. However, the household survey has a more expansive scope than the establishment survey because it includes the self-employed, unpaid family workers, agricultural workers, and private household workers, who are excluded by the establishment survey. The household survey also provides estimates of employment for demographic groups.

Are undocumented immigrants counted in the surveys?

Neither the establishment nor household survey is designed to identify the legal status of workers. Thus, while it is likely that both surveys include at least some undocumented immigrants, it is not possible to determine how many are counted in either survey. The household survey does include questions about whether respondents were born outside the United States. Data from these questions show that foreign-born workers accounted for 15.6 percent of the labor force in 2008.

Why does the establishment survey have revisions?

The establishment survey revises published estimates to improve its data series by incorporating additional information that was not available at the time of the initial publication of the estimates. The establishment survey revises its initial monthly estimates twice, in the immediately succeeding 2 months, to incorporate additional sample receipts from respondents in the survey and recalculated seasonal adjustment factors. For more information on the monthly revisions, please visit www.bls.gov/ces/cesrevinfo.htm.

On an annual basis, the establishment survey incorporates a benchmark revision that re-anchors estimates to nearly complete employment counts available from unemployment insurance tax records. The benchmark helps to control for sampling and modeling errors in the estimates. For more information on the annual benchmark revision, please visit www.bls.gov/web/cesbmart.htm.

Does the establishment survey sample include small firms?

Yes; about 40 percent of the establishment survey sample is comprised of business establishments with fewer than 20 employees. The establishment survey sample is designed to maximize the reliability of the total nonfarm employment estimate; firms from all size classes and industries are appropriately sampled to achieve that goal.

Does the establishment survey account for employment from new businesses?

Yes; monthly establishment survey estimates include an adjustment to account for the net employment change generated by business births and deaths. The adjustment comes from an econometric model that forecasts the monthly net jobs impact of business births and deaths based on the actual past values of the net impact that can be observed with a lag from the Quarterly Census of Employment and Wages. The establishment survey uses modeling rather than sampling for this purpose because the survey is not immediately able to bring new businesses into the sample. There is an unavoidable lag between the birth of a new firm and its appearance on the sampling frame and availability for selection. BLS adds new businesses to the survey twice a year.

Is the count of unemployed persons limited to just those people receiving unemployment insurance benefits?

No; the estimate of unemployment is based on a monthly sample survey of households. All persons who are without jobs and are actively seeking and available to work are included among the unemployed. (People on temporary layoff are included even if they do not actively seek work.) There is no requirement or question relating to unemployment insurance benefits in the monthly survey.

Does the official unemployment rate exclude people who have stopped looking for work?

Yes; however, there are separate estimates of persons outside the labor force who want a job, including those who have stopped looking because they believe no jobs are available (discouraged workers). In addition, alternative measures of labor underutilization (discouraged workers and other groups not officially counted as unemployed) are published each month in the Employment Situation news release.

Technical Note

This news release presents statistics from two major surveys, the Current Population Survey (household survey) and the Current Employment Statistics survey (establishment survey). The household survey provides the information on the labor force, employment, and unemployment that appears in the A tables, marked HOUSEHOLD DATA. It is a sample survey of about 60,000 households conducted by the U.S. Census Bureau for the Bureau of Labor Statistics (BLS).

The establishment survey provides the information on the employment, hours, and earnings of workers on nonfarm payrolls that appears in the B tables, marked ESTABLISHMENT DATA. This information is collected from payroll records by BLS in cooperation with state agencies. The sample includes about 160,000 businesses and government agencies covering approximately 400,000 individual worksites. The active sample includes about one-third of all nonfarm payroll workers. The sample is drawn from a sampling frame of unemployment insurance tax accounts.

For both surveys, the data for a given month relate to a particular week or pay period. In the household survey, the reference week is generally the calendar week that contains the 12th day of the month. In the establishment survey, the reference period is the pay period including the 12th, which may or may not correspond directly to the calendar week.

Coverage, definitions, and differences between surveys

Household survey. The sample is selected to reflect the entire civilian noninstitutional population. Based on responses to a series of questions on work and job search activities, each person 16 years and over in a sample household is classified as employed, unemployed, or not in the labor force.

People are classified as employed if they did any work at all as paid employees during the reference week; worked in their own business, profession, or on their own farm; or worked without pay at least 15 hours in a family business or farm. People are also counted as employed if they were temporarily absent from their jobs because of illness, bad weather, vacation, labor-management disputes, or personal reasons.

People are classified as unemployed if they meet all of the following criteria: They had no employment during the reference week; they were available for work at that time; and they made specific efforts to find employment sometime during the 4-week period ending with the reference week. Persons laid off from a job and expecting recall need not be looking for work to be counted as unemployed. The unemployment data derived from the household survey in no way depend upon the eligibility for or receipt of unemployment insurance benefits.

The civilian labor force is the sum of employed and unemployed persons. Those not classified as employed or unemployed are *not in the labor force.* The *unemployment rate* is the number unemployed as a percent of the labor force. The *labor force participation rate* is the labor force as a percent of the population, and the *employment-population ratio* is the employed as a percent of the population.

Establishment survey. The sample establishments are drawn from private nonfarm businesses such as factories, offices, and stores, as well as federal, state, and local government entities. *Employees on nonfarm payrolls* are those who received pay for any part of the reference pay period, including persons on paid leave. Persons are counted in each job they hold. *Hours and earnings* data are for private businesses and relate only to production workers in the goods-producing sector and nonsupervisory workers in the service-providing sector. Industries are classified on the basis of their principal activity in accordance with the 2007 version of the North American Industry Classification System.

Differences in employment estimates. The numerous conceptual and methodological differences between the household and establishment surveys result in important distinctions in the employment estimates derived from the surveys. Among these are:

- The household survey includes agricultural workers, the self-employed, unpaid family workers, and private household workers among the employed. These groups are excluded from the establishment survey.

- The household survey includes people on unpaid leave among the employed. The establishment survey does not.

- The household survey is limited to workers 16 years of age and older. The establishment survey is not limited by age.

- The household survey has no duplication of individuals, because individuals are counted only once, even if they hold more than one job. In the establishment survey, employees working at more than one job and thus appearing on more than one payroll would be counted separately for each appearance.

Seasonal adjustment

Over the course of a year, the size of the nation's labor force and the levels of employment and unemployment undergo sharp fluctuations due to such seasonal events as changes in weather, reduced or expanded production, harvests, major holidays, and the opening and closing of schools. The effect of such seasonal variation can be very large; seasonal fluctuations may account for as much as 95 percent of the month-to-month changes in unemployment.

Because these seasonal events follow a more or less regular pattern each year, their influence on statistical trends can be eliminated by adjusting the statistics from month to month. These adjustments make nonseasonal developments, such as declines in economic activity or increases in the participation of women in the labor force, easier to spot. For example, the large number of youth entering the labor force each June is likely to obscure any other changes that have taken place relative to May, making it difficult to determine if the level of economic activity has risen or declined. However, because the effect of students finishing school in previous years is known, the statistics for the current year can be adjusted to allow for a comparable change. Insofar as the seasonal adjustment is made correctly, the adjusted figure provides a more useful tool with which to analyze changes in economic activity.

Most seasonally adjusted series are independently adjusted in both the household and establishment surveys. However, the adjusted series for many major estimates, such as total payroll employment, employment in most supersectors, total employment, and unemployment are computed by aggregating independently adjusted component series. For example, total unemployment is derived by summing the adjusted series for four major age-sex components; this differs from the unemployment estimate that would be obtained by directly adjusting the total or by combining the duration, reasons, or more detailed age categories.

For both the household and establishment surveys, a concurrent seasonal adjustment methodology is used in which new seasonal factors are calculated each month, using all relevant data, up to and including the data for the current month. In the household survey, new seasonal factors are used to adjust only the current month's data. In the establishment survey, however, new seasonal factors are used each month to adjust the three most recent monthly estimates. In both surveys, revisions to historical data are made once a year.

Reliability of the estimates

Statistics based on the household and establishment surveys are subject to both sampling and nonsampling error. When a sample rather than the entire population is surveyed, there is a chance that the sample estimates may differ from the "true" population values they represent. The exact difference, or *sampling error*, varies depending on the particular sample selected, and this variability is measured by the standard error of the estimate. There is about a 90-percent chance, or level of confidence, that an estimate based on a sample will differ by no more than 1.6 standard errors from the "true" population value because of sampling error. BLS analyses are generally conducted at the 90-percent level of confidence.

For example, the confidence interval for the monthly change in total employment from the household survey is on the order of plus or minus 430,000. Suppose the estimate of total employment increases by 100,000 from one month to the next. The 90-percent confidence interval on the monthly change would range from -330,000 to 530,000 (100,000 +/-430,000). These figures do not mean that the sample results are off by these magnitudes, but rather that there is about a 90-percent chance that the "true" over-the-month change lies within this interval. Since this range includes values of less than zero, we could not say with confidence that employment had, in fact, increased. If, however, the reported employment rise was half a million, then all of the values within the 90-percent confidence interval would be greater than zero. In this case, it is likely (at least a 90-percent chance) that an employment rise had, in fact, occurred. At an unemployment rate of around 5.5 percent, the 90-percent confidence interval for the monthly change in unemployment is about +/-280,000, and for the monthly change in the unemployment rate it is about +/-.19 percentage point.

In general, estimates involving many individuals or establishments have lower standard errors (relative to the size of the estimate) than estimates which are based on a small number of observations. The precision of estimates is also improved when the data are cumulated over time such as for quarterly and annual averages. The seasonal adjustment process can also improve the stability of the monthly estimates.

The household and establishment surveys are also affected by *nonsampling error*. Nonsampling errors can occur for many reasons, including the failure to sample a segment of the population, inability to obtain information for all respondents in the sample, inability or unwillingness of respondents to provide correct information on a timely basis, mistakes made by respondents, and errors made in the collection or processing of the data.

For example, in the establishment survey, estimates for the most recent 2 months are based on incomplete returns; for this reason, these estimates are labeled preliminary in the tables. It is only after two successive revisions to a monthly estimate, when nearly all sample reports have been received, that the estimate is considered final.

Another major source of nonsampling error in the establishment survey is the inability to capture, on a timely basis, employment generated by new firms. To correct for this systematic underestimation of employment growth, an estimation procedure with two components is used to account for business births. The first component uses business deaths to impute employment for business births. This is incorporated into the sample-based link relative estimate procedure by simply not reflecting sample units going out of business, but imputing to them the same trend as the other firms in the sample. The second component is an ARIMA time series model designed to estimate the residual net birth/death employment not accounted for by the imputation. The historical time series used to create and test the ARIMA model was derived from the unemployment insurance universe micro-level database, and reflects the actual residual net of births and deaths over the past 5 years.

The sample-based estimates from the establishment survey are adjusted once a year (on a lagged basis) to universe counts of payroll employment obtained from administrative records of the unemployment insurance program. The difference between the March sample-based employment estimates and the March universe counts is known as a benchmark revision, and serves as a rough proxy for total survey error. The new benchmarks also incorporate changes in the classification of industries. Over the past decade, absolute benchmark revisions for total nonfarm employment have averaged 0.2 percent, with a range from 0.1 percent to 0.6 percent.

Other information

Information in this release will be made available to sensory impaired individuals upon request. Voice phone: (202) 691-5200; TDD message referral phone: 1-800-877-8339.

HOUSEHOLD DATA

Table A-1. Employment status of the civilian population by sex and age

(Numbers in thousands)

Employment status, sex, and age	Not seasonally adjusted			Seasonally adjusted [1]					
	July 2008	June 2009	July 2009	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009	July 2009
TOTAL									
Civilian noninstitutional population	233,864	235,655	235,870	233,864	235,086	235,271	235,452	235,655	235,870
Civilian labor force	156,300	155,921	156,255	154,506	154,048	154,731	155,081	154,926	154,504
Participation rate	66.8	66.2	66.2	66.1	65.5	65.8	65.9	65.7	65.5
Employed	146,867	140,826	141,055	145,596	140,887	141,007	140,570	140,196	140,041
Employment-population ratio	62.8	59.8	59.8	62.3	59.9	59.9	59.7	59.5	59.4
Unemployed	9,433	15,095	15,201	8,910	13,161	13,724	14,511	14,729	14,462
Unemployment rate	6.0	9.7	9.7	5.8	8.5	8.9	9.4	9.5	9.4
Not in labor force	77,564	79,734	79,614	79,358	81,038	80,541	80,371	80,729	81,366
Persons who currently want a job	5,213	6,454	6,244	5,033	5,814	5,935	5,861	5,884	5,990
Men, 16 years and over									
Civilian noninstitutional population	113,154	114,060	114,173	113,154	113,758	113,857	113,953	114,060	114,173
Civilian labor force	84,113	83,141	83,375	82,829	81,804	82,358	82,724	82,529	82,310
Participation rate	74.3	72.9	73.0	73.2	71.9	72.3	72.6	72.4	72.1
Employed	78,991	74,494	74,861	77,683	74,053	74,116	74,033	73,777	73,703
Employment-population ratio	69.8	65.3	65.6	68.7	65.1	65.1	65.0	64.7	64.6
Unemployed	5,122	8,647	8,515	5,146	7,751	8,242	8,691	8,751	8,607
Unemployment rate	6.1	10.4	10.2	6.2	9.5	10.0	10.5	10.6	10.5
Not in labor force	29,040	30,919	30,798	30,324	31,954	31,498	31,229	31,532	31,863
Men, 20 years and over									
Civilian noninstitutional population	104,490	105,412	105,530	104,490	105,095	105,196	105,299	105,412	105,530
Civilian labor force	79,752	79,245	79,337	79,286	78,578	79,081	79,395	79,291	79,045
Participation rate	76.3	75.2	75.2	75.9	74.8	75.2	75.4	75.2	74.9
Employed	75,643	71,738	71,911	74,973	71,655	71,678	71,593	71,387	71,319
Employment-population ratio	72.4	68.1	68.1	71.8	68.2	68.1	68.0	67.7	67.6
Unemployed	4,110	7,507	7,427	4,313	6,923	7,403	7,802	7,904	7,726
Unemployment rate	5.2	9.5	9.4	5.4	8.8	9.4	9.8	10.0	9.8
Not in labor force	24,738	26,167	26,193	25,204	26,516	26,115	25,904	26,121	26,485
Women, 16 years and over									
Civilian noninstitutional population	120,710	121,594	121,696	120,710	121,328	121,415	121,499	121,594	121,696
Civilian labor force	72,187	72,780	72,880	71,676	72,244	72,372	72,357	72,397	72,194
Participation rate	59.8	59.9	59.9	59.4	59.5	59.6	59.6	59.5	59.3
Employed	67,876	66,332	66,194	67,913	66,834	66,890	66,537	66,419	66,339
Employment-population ratio	56.2	54.6	54.4	56.3	55.1	55.1	54.8	54.6	54.5
Unemployed	4,311	6,448	6,686	3,763	5,410	5,482	5,820	5,978	5,855
Unemployment rate	6.0	8.9	9.2	5.3	7.5	7.6	8.0	8.3	8.1
Not in labor force	48,523	48,815	48,816	49,034	49,084	49,042	49,142	49,197	49,503
Women, 20 years and over									
Civilian noninstitutional population	112,290	113,189	113,296	112,290	112,908	112,999	113,089	113,189	113,296
Civilian labor force	68,072	68,906	68,993	68,273	68,977	69,148	69,112	69,060	68,985
Participation rate	60.6	60.9	60.9	60.8	61.1	61.2	61.1	61.0	60.9
Employed	64,526	63,480	63,182	65,103	64,148	64,226	63,895	63,810	63,789
Employment-population ratio	57.5	56.1	55.8	58.0	56.8	56.8	56.5	56.4	56.3
Unemployed	3,546	5,426	5,811	3,170	4,828	4,922	5,217	5,249	5,196
Unemployment rate	5.2	7.9	8.4	4.6	7.0	7.1	7.5	7.6	7.5
Not in labor force	44,218	44,284	44,303	44,017	43,931	43,850	43,976	44,130	44,311
Both sexes, 16 to 19 years									
Civilian noninstitutional population	17,084	17,053	17,044	17,084	17,083	17,076	17,064	17,053	17,044
Civilian labor force	8,476	7,770	7,925	6,947	6,493	6,501	6,573	6,575	6,474
Participation rate	49.6	45.6	46.5	40.7	38.0	38.1	38.5	38.6	38.0
Employed	6,698	5,608	5,962	5,520	5,083	5,103	5,082	4,999	4,933
Employment-population ratio	39.2	32.9	35.0	32.3	29.8	29.9	29.8	29.3	28.9
Unemployed	1,777	2,162	1,963	1,427	1,410	1,398	1,491	1,576	1,541
Unemployment rate	21.0	27.8	24.8	20.5	21.7	21.5	22.7	24.0	23.8
Not in labor force	8,608	9,284	9,118	10,137	10,590	10,575	10,491	10,478	10,570

[1] The population figures are not adjusted for seasonal variation; therefore, identical numbers appear in the unadjusted and seasonally adjusted columns.
NOTE: Updated population controls are introduced annually with the release of January data.

Table A-2. Employment status of the civilian population by race, sex, and age

(Numbers in thousands)

Employment status, race, sex, and age	Not seasonally adjusted			Seasonally adjusted [1]					
	July 2008	June 2009	July 2009	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009	July 2009
WHITE									
Civilian noninstitutional population	189,587	190,801	190,944	189,587	190,436	190,552	190,667	190,801	190,944
Civilian labor force	127,164	126,986	127,069	125,979	125,599	126,110	126,423	126,199	125,997
Participation rate	67.1	66.6	66.5	66.4	66.0	66.2	66.3	66.1	66.0
Employed	120,357	115,772	115,861	119,432	115,693	115,977	115,561	115,202	115,123
Employment-population ratio	63.5	60.7	60.7	63.0	60.8	60.9	60.6	60.4	60.3
Unemployed	6,807	11,214	11,209	6,547	9,906	10,133	10,862	10,997	10,874
Unemployment rate	5.4	8.8	8.8	5.2	7.9	8.0	8.6	8.7	8.6
Not in labor force	62,422	63,815	63,875	63,608	64,837	64,441	64,244	64,601	64,947
Men, 20 years and over									
Civilian labor force	66,010	65,662	65,692	65,786	65,032	65,509	65,766	65,732	65,643
Participation rate	76.7	75.7	75.7	76.4	75.2	75.7	75.9	75.8	75.6
Employed	63,055	59,963	60,091	62,624	59,811	59,967	59,820	59,656	59,701
Employment-population ratio	73.3	69.1	69.2	72.8	69.1	69.3	69.0	68.8	68.8
Unemployed	2,956	5,699	5,602	3,161	5,221	5,543	5,946	6,076	5,941
Unemployment rate	4.5	8.7	8.5	4.8	8.0	8.5	9.0	9.2	9.1
Women, 20 years and over									
Civilian labor force	54,186	54,900	54,853	54,459	55,115	55,227	55,192	55,068	54,987
Participation rate	59.9	60.3	60.2	60.2	60.7	60.8	60.7	60.5	60.4
Employed	51,637	50,990	50,696	52,169	51,519	51,695	51,385	51,304	51,245
Employment-population ratio	57.1	56.0	55.6	57.7	56.7	56.9	56.5	56.4	56.3
Unemployed	2,549	3,910	4,157	2,290	3,596	3,533	3,807	3,765	3,742
Unemployment rate	4.7	7.1	7.6	4.2	6.5	6.4	6.9	6.8	6.8
Both sexes, 16 to 19 years									
Civilian labor force	6,968	6,424	6,525	5,734	5,452	5,374	5,465	5,400	5,367
Participation rate	53.2	49.3	50.1	43.8	41.7	41.1	41.9	41.4	41.2
Employed	5,665	4,819	5,075	4,639	4,363	4,316	4,356	4,243	4,176
Employment-population ratio	43.3	36.9	38.9	35.4	33.4	33.0	33.4	32.5	32.0
Unemployed	1,303	1,605	1,450	1,095	1,089	1,058	1,108	1,156	1,191
Unemployment rate	18.7	25.0	22.2	19.1	20.0	19.7	20.3	21.4	22.2
BLACK OR AFRICAN AMERICAN									
Civilian noninstitutional population	27,854	28,217	28,252	27,854	28,118	28,153	28,184	28,217	28,252
Civilian labor force	18,097	17,911	18,085	17,744	17,542	17,816	17,737	17,700	17,684
Participation rate	65.0	63.5	64.0	63.7	62.4	63.3	62.9	62.7	62.6
Employed	16,132	15,174	15,218	15,989	15,212	15,142	15,095	15,103	15,111
Employment-population ratio	57.9	53.8	53.9	57.4	54.1	53.8	53.6	53.5	53.5
Unemployed	1,965	2,737	2,867	1,755	2,330	2,673	2,642	2,597	2,573
Unemployment rate	10.9	15.3	15.9	9.9	13.3	15.0	14.9	14.7	14.5
Not in labor force	9,757	10,306	10,167	10,111	10,576	10,337	10,446	10,517	10,568
Men, 20 years and over									
Civilian labor force	8,067	7,956	7,976	7,975	7,917	7,990	8,000	7,929	7,896
Participation rate	72.0	70.0	70.1	71.2	70.0	70.5	70.5	69.8	69.4
Employed	7,223	6,672	6,693	7,152	6,700	6,620	6,656	6,633	6,645
Employment-population ratio	64.5	58.7	58.8	63.9	59.2	58.4	58.7	58.4	58.4
Unemployed	844	1,284	1,283	822	1,218	1,370	1,345	1,297	1,251
Unemployment rate	10.5	16.1	16.1	10.3	15.4	17.2	16.8	16.4	15.8
Women, 20 years and over									
Civilian labor force	9,019	9,076	9,154	8,967	8,932	9,064	9,000	9,042	9,045
Participation rate	64.5	64.1	64.5	64.2	63.3	64.1	63.6	63.8	63.8
Employed	8,267	8,018	7,951	8,291	8,045	8,025	7,993	8,018	7,988
Employment-population ratio	59.1	56.6	56.1	59.3	57.0	56.8	56.5	56.6	56.3
Unemployed	752	1,058	1,203	675	887	1,038	1,007	1,024	1,057
Unemployment rate	8.3	11.7	13.1	7.5	9.9	11.5	11.2	11.3	11.7
Both sexes, 16 to 19 years									
Civilian labor force	1,011	879	955	802	692	762	736	729	744
Participation rate	37.7	32.7	35.5	30.0	25.7	28.3	27.4	27.1	27.7
Employed	642	484	574	545	467	497	446	453	479
Employment-population ratio	24.0	18.0	21.4	20.4	17.4	18.5	16.6	16.9	17.8
Unemployed	369	395	380	257	225	265	290	276	265
Unemployment rate	36.5	45.0	39.9	32.0	32.5	34.7	39.4	37.9	35.7

See footnotes at end of table.

HOUSEHOLD DATA

Table A-2. Employment status of the civilian population by race, sex, and age — Continued

(Numbers in thousands)

Employment status, race, sex, and age	Not seasonally adjusted			Seasonally adjusted [1]					
	July 2008	June 2009	July 2009	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009	July 2009
ASIAN									
Civilian noninstitutional population	10,802	10,897	10,903	(2)	(2)	(2)	(2)	(2)	(2)
Civilian labor force	7,326	7,322	7,394	(2)	(2)	(2)	(2)	(2)	(2)
Participation rate	67.8	67.2	67.8	(2)	(2)	(2)	(2)	(2)	(2)
Employed	7,030	6,719	6,780	(2)	(2)	(2)	(2)	(2)	(2)
Employment-population ratio	65.1	61.7	62.2	(2)	(2)	(2)	(2)	(2)	(2)
Unemployed	296	603	614	(2)	(2)	(2)	(2)	(2)	(2)
Unemployment rate	4.0	8.2	8.3	(2)	(2)	(2)	(2)	(2)	(2)
Not in labor force	3,476	3,575	3,509	(2)	(2)	(2)	(2)	(2)	(2)

[1] The population figures are not adjusted for seasonal variation; therefore, identical numbers appear in the unadjusted and seasonally adjusted columns.
[2] Data not available.

NOTE: Estimates for the above race groups will not sum to totals shown in table A-1 because data are not presented for all races. Updated population controls are introduced annually with the release of January data.

Table A-3. Employment status of the Hispanic or Latino population by sex and age

(Numbers in thousands)

Employment status, sex, and age	Not seasonally adjusted			Seasonally adjusted [1]					
	July 2008	June 2009	July 2009	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009	July 2009
HISPANIC OR LATINO ETHNICITY									
Civilian noninstitutional population	32,179	32,839	32,926	32,179	32,585	32,671	32,753	32,839	32,926
Civilian labor force	22,193	22,403	22,695	22,062	22,175	22,376	22,438	22,347	22,526
Participation rate	69.0	68.2	68.9	68.6	68.1	68.5	68.5	68.1	68.4
Employed	20,505	19,685	19,849	20,396	19,640	19,854	19,595	19,623	19,745
Employment-population ratio	63.7	59.9	60.3	63.4	60.3	60.8	59.8	59.8	60.0
Unemployed	1,688	2,718	2,846	1,665	2,536	2,521	2,843	2,724	2,781
Unemployment rate	7.6	12.1	12.5	7.5	11.4	11.3	12.7	12.2	12.3
Not in labor force	9,986	10,436	10,232	10,117	10,410	10,295	10,315	10,491	10,400
Men, 20 years and over									
Civilian labor force	12,661	12,642	12,824	(2)	(2)	(2)	(2)	(2)	(2)
Participation rate	84.5	82.7	83.7	(2)	(2)	(2)	(2)	(2)	(2)
Employed	11,937	11,290	11,384	(2)	(2)	(2)	(2)	(2)	(2)
Employment-population ratio	79.6	73.9	74.3	(2)	(2)	(2)	(2)	(2)	(2)
Unemployed	725	1,352	1,440	(2)	(2)	(2)	(2)	(2)	(2)
Unemployment rate	5.7	10.7	11.2	(2)	(2)	(2)	(2)	(2)	(2)
Women, 20 years and over									
Civilian labor force	8,268	8,527	8,553	(2)	(2)	(2)	(2)	(2)	(2)
Participation rate	58.5	59.1	59.1	(2)	(2)	(2)	(2)	(2)	(2)
Employed	7,650	7,542	7,541	(2)	(2)	(2)	(2)	(2)	(2)
Employment-population ratio	54.1	52.2	52.1	(2)	(2)	(2)	(2)	(2)	(2)
Unemployed	618	985	1,013	(2)	(2)	(2)	(2)	(2)	(2)
Unemployment rate	7.5	11.5	11.8	(2)	(2)	(2)	(2)	(2)	(2)
Both sexes, 16 to 19 years									
Civilian labor force	1,264	1,234	1,317	(2)	(2)	(2)	(2)	(2)	(2)
Participation rate	41.5	39.6	42.1	(2)	(2)	(2)	(2)	(2)	(2)
Employed	919	854	924	(2)	(2)	(2)	(2)	(2)	(2)
Employment-population ratio	30.2	27.4	29.6	(2)	(2)	(2)	(2)	(2)	(2)
Unemployed	345	381	393	(2)	(2)	(2)	(2)	(2)	(2)
Unemployment rate	27.3	30.8	29.8	(2)	(2)	(2)	(2)	(2)	(2)

[1] The population figures are not adjusted for seasonal variation; therefore, identical numbers appear in the unadjusted and seasonally adjusted columns.
[2] Data not available.

NOTE: Persons whose ethnicity is identified as Hispanic or Latino may be of any race. Updated population controls are introduced annually with the release of January data.

HOUSEHOLD DATA

Table A-4. Employment status of the civilian population 25 years and over by educational attainment

(Numbers in thousands)

Educational attainment	Not seasonally adjusted			Seasonally adjusted					
	July 2008	June 2009	July 2009	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009	July 2009
Less than a high school diploma									
Civilian labor force	11,877	12,545	12,142	12,174	11,997	12,027	12,210	12,363	12,461
Participation rate	46.6	47.0	47.3	47.8	45.7	45.7	45.9	46.3	48.5
Employed	10,897	10,744	10,352	11,124	10,399	10,251	10,321	10,447	10,537
Employment-population ratio	42.8	40.3	40.3	43.7	39.6	38.9	38.8	39.2	41.0
Unemployed	980	1,802	1,790	1,050	1,598	1,776	1,889	1,916	1,925
Unemployment rate	8.3	14.4	14.7	8.6	13.3	14.8	15.5	15.5	15.4
High school graduates, no college [1]									
Civilian labor force	38,248	38,208	37,832	38,819	38,434	38,687	38,757	38,694	38,362
Participation rate	62.5	62.4	61.7	63.4	62.3	63.0	63.1	63.2	62.5
Employed	36,211	34,695	34,269	36,757	34,981	35,086	34,881	34,898	34,760
Employment-population ratio	59.2	56.7	55.9	60.1	56.7	57.1	56.8	57.0	56.7
Unemployed	2,037	3,514	3,563	2,062	3,454	3,601	3,875	3,796	3,602
Unemployment rate	5.3	9.2	9.4	5.3	9.0	9.3	10.0	9.8	9.4
Some college or associate degree									
Civilian labor force	36,791	36,546	36,839	36,534	36,921	36,959	36,860	36,646	36,564
Participation rate	71.7	70.8	71.2	71.2	71.8	71.7	71.7	71.0	70.6
Employed	35,035	33,614	33,800	34,855	34,267	34,207	34,013	33,713	33,679
Employment-population ratio	68.3	65.1	65.3	68.0	66.6	66.4	66.2	65.3	65.1
Unemployed	1,756	2,932	3,039	1,679	2,653	2,752	2,847	2,933	2,885
Unemployment rate	4.8	8.0	8.2	4.6	7.2	7.4	7.7	8.0	7.9
Bachelor's degree and higher [2]									
Civilian labor force	44,955	45,242	45,751	45,050	45,401	45,442	45,500	45,527	45,691
Participation rate	77.0	77.3	76.9	77.1	78.1	77.7	77.8	77.7	76.8
Employed	43,703	43,048	43,330	43,936	43,431	43,466	43,332	43,368	43,546
Employment-population ratio	74.8	73.5	72.9	75.2	74.7	74.4	74.1	74.1	73.2
Unemployed	1,252	2,194	2,422	1,114	1,970	1,977	2,167	2,158	2,145
Unemployment rate	2.8	4.8	5.3	2.5	4.3	4.4	4.8	4.7	4.7

[1] Includes persons with a high school diploma or equivalent.
[2] Includes persons with bachelor's, master's, professional, and doctoral degrees.
NOTE: Updated population controls are introduced annually with the release of January data.

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Table A-5. Employed persons by class of worker and part-time status

(In thousands)

Category	Not seasonally adjusted			Seasonally adjusted					
	July 2008	June 2009	July 2009	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009	July 2009
CLASS OF WORKER									
Agriculture and related industries	2,372	2,351	2,361	2,142	2,050	2,134	2,173	2,165	2,148
Wage and salary workers	1,444	1,366	1,392	1,265	1,167	1,209	1,256	1,232	1,230
Self-employed workers	894	941	926	846	875	887	882	896	876
Unpaid family workers	35	43	42	(1)	(1)	(1)	(1)	(1)	(1)
Nonagricultural industries	144,495	138,475	138,694	143,453	138,842	138,828	138,296	137,812	137,675
Wage and salary workers	134,662	129,255	129,619	133,894	129,478	129,724	129,298	128,939	128,939
Government	20,509	21,260	20,766	21,129	20,904	21,211	21,247	21,446	21,367
Private industries	114,153	107,995	108,853	112,818	108,674	108,555	108,054	107,498	107,591
Private households	873	908	923	(1)	(1)	(1)	(1)	(1)	(1)
Other industries	113,280	107,087	107,930	112,036	107,898	107,813	107,238	106,631	106,728
Self-employed workers	9,727	9,138	9,007	9,483	9,184	9,052	8,990	8,891	8,801
Unpaid family workers	106	83	68	(1)	(1)	(1)	(1)	(1)	(1)
PERSONS AT WORK PART TIME 2									
All industries:									
Part time for economic reasons	6,054	9,301	9,103	5,813	9,049	8,910	9,084	8,989	8,798
Slack work or business conditions	4,174	6,616	6,711	4,220	6,857	6,699	6,794	6,783	6,849
Could only find part-time work	1,481	2,263	1,978	1,300	1,839	1,810	1,922	1,980	1,835
Part time for noneconomic reasons	17,442	17,712	17,235	19,348	18,833	19,065	18,872	18,718	19,018
Nonagricultural industries:									
Part time for economic reasons	5,947	9,190	8,977	5,693	8,942	8,826	8,928	8,845	8,647
Slack work or business conditions	4,111	6,537	6,606	4,160	6,773	6,650	6,681	6,699	6,733
Could only find part-time work	1,469	2,245	1,974	1,287	1,850	1,802	1,909	1,969	1,776
Part time for noneconomic reasons	17,080	17,327	16,869	18,992	18,493	18,661	18,502	18,358	18,621

1 Data not available.

2 Persons at work excludes employed persons who were absent from their jobs during the entire reference week for reasons such as vacation, illness, or industrial dispute. Part time for noneconomic reasons excludes persons who usually work full time but worked only 1 to 34 hours during the reference week for reasons such as holidays, illness, and bad weather.

NOTE: Detail for the seasonally adjusted data shown in this table will not necessarily add to totals because of the independent seasonal adjustment of the various series. Updated population controls are introduced annually with the release of January data.

HOUSEHOLD DATA

Table A-6. Selected employment indicators

(In thousands)

Characteristic	Not seasonally adjusted			Seasonally adjusted					
	July 2008	June 2009	July 2009	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009	July 2009
AGE AND SEX									
Total, 16 years and over	146,867	140,826	141,055	145,596	140,887	141,007	140,570	140,196	140,041
16 to 19 years	6,698	5,608	5,962	5,520	5,083	5,103	5,082	4,999	4,933
16 to 17 years	2,445	1,940	2,136	1,969	1,755	1,737	1,795	1,732	1,718
18 to 19 years	4,253	3,667	3,826	3,572	3,300	3,353	3,260	3,251	3,225
20 years and over	140,169	135,218	135,093	140,076	135,804	135,904	135,488	135,197	135,108
20 to 24 years	14,323	13,118	13,342	13,697	13,090	13,090	12,842	12,774	12,790
25 years and over	125,846	122,100	121,751	126,526	122,662	122,838	122,650	122,539	122,455
25 to 54 years	99,215	95,156	94,873	99,640	95,720	95,805	95,394	95,391	95,297
25 to 34 years	31,465	30,054	30,128	31,449	30,211	30,140	29,955	30,018	30,079
35 to 44 years	33,371	31,634	31,421	33,556	31,746	31,770	31,681	31,734	31,613
45 to 54 years	34,379	33,468	33,324	34,635	33,763	33,896	33,758	33,639	33,606
55 years and over	26,631	26,944	26,878	26,886	26,942	27,032	27,256	27,147	27,158
Men, 16 years and over	78,991	74,494	74,861	77,683	74,053	74,116	74,033	73,777	73,703
16 to 19 years	3,348	2,755	2,950	2,709	2,398	2,438	2,440	2,390	2,383
16 to 17 years	1,215	976	1,092	926	803	817	851	821	826
18 to 19 years	2,133	1,779	1,857	1,789	1,579	1,635	1,580	1,576	1,562
20 years and over	75,643	71,738	71,911	74,973	71,655	71,678	71,593	71,387	71,319
20 to 24 years	7,598	6,808	6,930	7,159	6,656	6,701	6,574	6,582	6,546
25 years and over	68,045	64,930	64,980	67,894	65,031	64,960	65,001	64,855	64,828
25 to 54 years	53,755	50,727	50,771	53,589	50,865	50,802	50,672	50,640	50,600
25 to 34 years	17,370	16,257	16,399	17,231	16,288	16,199	16,082	16,194	16,231
35 to 44 years	18,147	16,925	16,923	18,103	17,027	17,027	17,002	16,926	16,898
45 to 54 years	18,237	17,545	17,448	18,254	17,550	17,576	17,588	17,520	17,470
55 years and over	14,290	14,202	14,210	14,306	14,166	14,157	14,329	14,214	14,228
Women, 16 years and over	67,876	66,332	66,194	67,913	66,834	66,890	66,537	66,419	66,339
16 to 19 years	3,350	2,852	3,012	2,811	2,685	2,664	2,642	2,609	2,550
16 to 17 years	1,230	964	1,043	1,043	952	920	944	911	892
18 to 19 years	2,119	1,888	1,969	1,783	1,721	1,718	1,681	1,675	1,663
20 years and over	64,526	63,480	63,182	65,103	64,148	64,226	63,895	63,810	63,789
20 to 24 years	6,725	6,310	6,412	6,538	6,434	6,389	6,268	6,193	6,244
25 years and over	57,802	57,170	56,770	58,631	57,631	57,878	57,649	57,684	57,627
25 to 54 years	45,460	44,429	44,102	46,052	44,855	45,003	44,722	44,751	44,697
25 to 34 years	14,095	13,796	13,728	14,218	13,922	13,941	13,873	13,825	13,847
35 to 44 years	15,224	14,709	14,498	15,453	14,719	14,742	14,679	14,808	14,714
45 to 54 years	16,142	15,923	15,876	16,380	16,214	16,320	16,170	16,118	16,136
55 years and over	12,341	12,742	12,668	12,580	12,776	12,875	12,927	12,933	12,929
MARITAL STATUS									
Married men, spouse present	46,034	44,263	43,900	46,093	44,470	44,469	44,255	44,294	43,992
Married women, spouse present	35,571	35,274	34,872	36,110	35,481	35,444	35,391	35,464	35,377
Women who maintain families	8,877	8,853	8,751	([1])	([1])	([1])	([1])	([1])	([1])
FULL- OR PART-TIME STATUS									
Full-time workers [2]	122,378	114,014	114,184	120,295	113,665	113,725	113,318	112,942	112,598
Part-time workers [3]	24,489	26,811	26,871	25,452	26,963	27,066	27,195	27,374	27,799
MULTIPLE JOBHOLDERS									
Total multiple jobholders	7,743	7,067	7,282	7,727	7,656	7,748	7,292	7,160	7,284
Percent of total employed	5.3	5.0	5.2	5.3	5.4	5.5	5.2	5.1	5.2

[1] Data not available.

[2] Employed full-time workers are persons who usually work 35 hours or more per week.

[3] Employed part-time workers are persons who usually work less than 35 hours per week.

NOTE: Detail for the seasonally adjusted data shown in this table will not necessarily add to totals because of the independent seasonal adjustment of the various series. Updated population controls are introduced annually with the release of January data.

Table A-7. Selected unemployment indicators, seasonally adjusted

Characteristic	Number of unemployed persons (in thousands)			Unemployment rates [1]					
	July 2008	June 2009	July 2009	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009	July 2009
AGE AND SEX									
Total, 16 years and over	8,910	14,729	14,462	5.8	8.5	8.9	9.4	9.5	9.4
16 to 19 years	1,427	1,576	1,541	20.5	21.7	21.5	22.7	24.0	23.8
16 to 17 years	653	580	585	24.9	23.7	23.0	23.4	25.1	25.4
18 to 19 years	763	1,009	962	17.6	20.9	21.3	22.9	23.7	23.0
20 years and over	7,483	13,153	12,922	5.1	8.0	8.3	8.8	8.9	8.7
20 to 24 years	1,584	2,283	2,302	10.4	14.0	14.7	15.0	15.2	15.3
25 years and over	5,971	10,877	10,743	4.5	7.2	7.5	8.1	8.2	8.1
25 to 54 years	4,927	8,812	8,717	4.7	7.6	7.8	8.4	8.5	8.4
25 to 34 years	1,898	3,359	3,344	5.7	9.0	9.7	10.5	10.1	10.0
35 to 44 years	1,646	2,796	2,706	4.7	7.2	7.5	8.1	8.1	7.9
45 to 54 years	1,383	2,657	2,667	3.8	6.6	6.4	6.8	7.3	7.4
55 years and over	1,042	2,048	1,965	3.7	6.2	6.4	6.7	7.0	6.7
Men, 16 years and over	5,146	8,751	8,607	6.2	9.5	10.0	10.5	10.6	10.5
16 to 19 years	834	847	881	23.5	25.7	25.6	26.7	26.2	27.0
16 to 17 years	383	285	316	29.3	28.2	26.3	26.1	25.8	27.7
18 to 19 years	450	579	577	20.1	24.6	25.3	27.8	26.9	27.0
20 years and over	4,313	7,904	7,726	5.4	8.8	9.4	9.8	10.0	9.8
20 to 24 years	946	1,370	1,347	11.7	16.7	17.5	17.5	17.2	17.1
25 years and over	3,392	6,532	6,446	4.8	7.9	8.3	9.0	9.2	9.0
25 to 54 years	2,823	5,346	5,306	5.0	8.3	8.8	9.5	9.5	9.5
25 to 34 years	1,141	2,075	2,031	6.2	10.1	11.1	11.9	11.4	11.1
35 to 44 years	941	1,649	1,644	4.9	7.7	8.2	9.0	8.9	8.9
45 to 54 years	741	1,622	1,631	3.9	7.1	7.1	7.7	8.5	8.5
55 years and over	569	1,186	1,140	3.8	6.3	6.7	7.0	7.7	7.4
Women, 16 years and over	3,763	5,978	5,855	5.3	7.5	7.6	8.0	8.3	8.1
16 to 19 years	593	729	659	17.4	17.8	17.4	18.6	21.8	20.5
16 to 17 years	270	295	269	20.5	19.4	19.9	20.7	24.4	23.2
18 to 19 years	313	430	385	14.9	17.2	17.1	17.5	20.4	18.8
20 years and over	3,170	5,249	5,196	4.6	7.0	7.1	7.5	7.6	7.5
20 to 24 years	638	913	955	8.9	11.0	11.5	12.2	12.8	13.3
25 years and over	2,580	4,345	4,297	4.2	6.5	6.6	7.0	7.0	6.9
25 to 54 years	2,104	3,467	3,411	4.4	6.7	6.7	7.2	7.2	7.1
25 to 34 years	757	1,284	1,312	5.1	7.6	7.9	8.9	8.5	8.7
35 to 44 years	705	1,147	1,063	4.4	6.5	6.7	7.0	7.2	6.7
45 to 54 years	643	1,036	1,036	3.8	6.1	5.7	5.9	6.0	6.0
55 years and over [2]	550	874	974	4.3	5.8	5.4	5.8	6.4	7.1
MARITAL STATUS									
Married men, spouse present	1,587	3,289	3,282	3.3	5.8	6.3	6.8	6.9	6.9
Married women, spouse present	1,278	2,120	2,045	3.4	5.4	5.5	5.7	5.6	5.5
Women who maintain families [2]	820	1,173	1,266	8.5	10.8	10.0	11.0	11.7	12.6
FULL- OR PART-TIME STATUS									
Full-time workers [3]	7,438	12,924	12,709	5.8	9.2	9.6	10.2	10.3	10.1
Part-time workers [4]	1,507	1,724	1,780	5.6	5.9	6.1	6.0	5.9	6.0

[1] Unemployment as a percent of the civilian labor force.
[2] Not seasonally adjusted.
[3] Full-time workers are unemployed persons who have expressed a desire to work full time (35 hours or more per week) or are on layoff from full-time jobs.
[4] Part-time workers are unemployed persons who have expressed a desire to work part time (less than 35 hours per week) or are on layoff from part-time jobs.

NOTE: Detail for the seasonally adjusted data shown in this table will not necessarily add to totals because of the independent seasonal adjustment of the various series. Updated population controls are introduced annually with the release of January data.

HOUSEHOLD DATA

Table A-8. Unemployed persons by reason for unemployment

(Numbers in thousands)

Reason	Not seasonally adjusted			Seasonally adjusted					
	July 2008	June 2009	July 2009	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009	July 2009
NUMBER OF UNEMPLOYED									
Job losers and persons who completed temporary jobs	4,562	9,194	9,447	4,595	8,243	8,814	9,546	9,649	9,560
On temporary layoff	1,134	1,503	1,804	1,041	1,557	1,625	1,832	1,762	1,680
Not on temporary layoff	3,428	7,691	7,643	3,554	6,686	7,189	7,714	7,886	7,880
Permanent job losers	2,512	6,294	6,320	(1)	(1)	(1)	(1)	(1)	(1)
Persons who completed temporary jobs	916	1,397	1,323	(1)	(1)	(1)	(1)	(1)	(1)
Job leavers	904	778	917	875	887	890	910	822	885
Reentrants	2,825	3,697	3,464	2,668	2,974	3,087	3,180	3,335	3,312
New entrants	1,142	1,425	1,373	818	868	900	956	947	967
PERCENT DISTRIBUTION									
Total unemployed	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Job losers and persons who completed temporary jobs	48.4	60.9	62.1	51.3	63.5	64.4	65.4	65.4	64.9
On temporary layoff	12.0	10.0	11.9	11.6	12.0	11.9	12.6	11.9	11.4
Not on temporary layoff	36.3	51.0	50.3	39.7	51.5	52.5	52.9	53.5	53.5
Job leavers	9.6	5.2	6.0	9.8	6.8	6.5	6.2	5.6	6.0
Reentrants	29.9	24.5	22.8	29.8	22.9	22.5	21.8	22.6	22.5
New entrants	12.1	9.4	9.0	9.1	6.7	6.6	6.6	6.4	6.6
UNEMPLOYED AS A PERCENT OF THE CIVILIAN LABOR FORCE									
Job losers and persons who completed temporary jobs	2.9	5.9	6.0	3.0	5.4	5.7	6.2	6.2	6.2
Job leavers	.6	.5	.6	.6	.6	.6	.6	.5	.6
Reentrants	1.8	2.4	2.2	1.7	1.9	2.0	2.1	2.2	2.1
New entrants	.7	.9	.9	.5	.6	.6	.6	.6	.6

[1] Data not available.

NOTE: Updated population controls are introduced annually with the release of January data.

HOUSEHOLD DATA

Table A-9. Unemployed persons by duration of unemployment

(Numbers in thousands)

Duration	Not seasonally adjusted			Seasonally adjusted					
	July 2008	June 2009	July 2009	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009	July 2009
NUMBER OF UNEMPLOYED									
Less than 5 weeks	3,121	3,899	3,456	2,884	3,371	3,346	3,275	3,204	3,233
5 to 14 weeks	3,291	3,648	4,091	2,853	4,041	3,982	4,321	4,066	3,557
15 weeks and over	3,021	7,548	7,654	3,168	5,715	6,211	7,002	7,833	7,880
15 to 26 weeks	1,360	3,329	2,720	1,450	2,534	2,531	3,054	3,452	2,916
27 weeks and over	1,661	4,218	4,934	1,718	3,182	3,680	3,948	4,381	4,965
Average (mean) duration, in weeks	16.3	22.5	24.1	17.3	20.1	21.4	22.5	24.5	25.1
Median duration, in weeks	8.9	14.5	14.7	9.8	11.2	12.5	14.9	17.9	15.7
PERCENT DISTRIBUTION									
Total unemployed	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Less than 5 weeks	33.1	25.8	22.7	32.4	25.7	24.7	22.4	21.2	22.0
5 to 14 weeks	34.9	24.2	26.9	32.0	30.8	29.4	29.6	26.9	24.2
15 weeks and over	32.0	50.0	50.4	35.6	43.5	45.9	48.0	51.9	53.7
15 to 26 weeks	14.4	22.1	17.9	16.3	19.3	18.7	20.9	22.9	19.9
27 weeks and over	17.6	27.9	32.5	19.3	24.2	27.2	27.0	29.0	33.8

NOTE: Updated population controls are introduced annually with the release of January data.

Table A-10. Employed and unemployed persons by occupation, not seasonally adjusted

(Numbers in thousands)

Occupation	Employed		Unemployed		Unemployment rates	
	July 2008	July 2009	July 2008	July 2009	July 2008	July 2009
Total, 16 years and over [1]	146,867	141,055	9,433	15,201	6.0	9.7
Management, professional, and related occupations	52,655	51,810	1,585	3,034	2.9	5.5
Management, business, and financial operations occupations	22,596	21,893	593	1,126	2.6	4.9
Professional and related occupations	30,059	29,917	992	1,909	3.2	6.0
Service occupations	25,613	25,831	1,880	2,756	6.8	9.6
Sales and office occupations	35,096	34,066	2,143	3,221	5.8	8.6
Sales and related occupations	15,995	16,016	1,055	1,450	6.2	8.3
Office and administrative support occupations	19,102	18,050	1,088	1,771	5.4	8.9
Natural resources, construction, and maintenance occupations	15,399	13,500	1,240	2,334	7.5	14.7
Farming, fishing, and forestry occupations	1,085	1,048	93	155	7.9	12.9
Construction and extraction occupations	9,086	7,492	864	1,686	8.7	18.4
Installation, maintenance, and repair occupations	5,227	4,961	283	493	5.1	9.0
Production, transportation, and material moving occupations	18,104	15,847	1,407	2,434	7.2	13.3
Production occupations	9,015	7,685	686	1,397	7.1	15.4
Transportation and material moving occupations	9,089	8,163	722	1,037	7.4	11.3

[1] Persons with no previous work experience and persons whose last job was in the Armed Forces are included in the unemployed total.
NOTE: Updated population controls are introduced annually with the release of January data.

HOUSEHOLD DATA

Table A-11. Unemployed persons by industry and class of worker, not seasonally adjusted

Industry and class of worker	Number of unemployed persons (in thousands)		Unemployment rates	
	July 2008	July 2009	July 2008	July 2009
Total, 16 years and over [1]	9,433	15,201	6.0	9.7
Nonagricultural private wage and salary workers	7,050	11,967	5.8	9.9
Mining, quarrying, and oil and gas extraction	13	95	1.5	12.6
Construction	783	1,687	8.0	18.2
Manufacturing	908	1,988	5.5	12.4
Durable goods	607	1,379	5.7	13.7
Nondurable goods	301	609	5.0	10.1
Wholesale and retail trade	1,329	1,854	6.5	9.0
Transportation and utilities	359	511	5.7	8.8
Information	141	373	4.1	11.5
Financial activities	350	570	3.6	6.1
Professional and business services	866	1,531	6.1	10.9
Education and health services	776	1,269	3.9	6.1
Leisure and hospitality	1,172	1,600	8.8	11.2
Other services	352	490	5.2	7.4
Agriculture and related private wage and salary workers	125	180	8.5	12.1
Government workers	770	1,129	3.6	5.1
Self employed and unpaid family workers	345	552	3.1	5.2

[1] Persons with no previous work experience are included in the unemployed total.

NOTE: Updated population controls are introduced annually with the release of January data. Effective with January 2009 data, industries reflect the introduction of the 2007 Census industry classification system into the Current Population Survey. This industry classification system is derived from the 2007 North American Industry Classification System. No historical data have been revised.

Table A-12. Alternative measures of labor underutilization

(Percent)

Measure	Not seasonally adjusted			Seasonally adjusted					
	July 2008	June 2009	July 2009	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009	July 2009
U-1 Persons unemployed 15 weeks or longer, as a percent of the civilian labor force	1.9	4.8	4.9	2.1	3.7	4.0	4.5	5.1	5.1
U-2 Job losers and persons who completed temporary jobs, as a percent of the civilian labor force	2.9	5.9	6.0	3.0	5.4	5.7	6.2	6.2	6.2
U-3 Total unemployed, as a percent of the civilian labor force (official unemployment rate)	6.0	9.7	9.7	5.8	8.5	8.9	9.4	9.5	9.4
U-4 Total unemployed plus discouraged workers, as a percent of the civilian labor force plus discouraged workers	6.3	10.1	10.2	6.0	8.9	9.3	9.8	10.0	9.8
U-5 Total unemployed, plus discouraged workers, plus all other marginally attached workers, as a percent of the civilian labor force plus all marginally attached workers	7.0	10.9	11.0	6.7	9.8	10.1	10.6	10.8	10.7
U-6 Total unemployed, plus all marginally attached workers, plus total employed part time for economic reasons, as a percent of the civilian labor force plus all marginally attached workers	10.8	16.8	16.8	10.4	15.6	15.8	16.4	16.5	16.3

NOTE: Marginally attached workers are persons who currently are neither working nor looking for work but indicate that they want and are available for a job and have looked for work sometime in the recent past. Discouraged workers, a subset of the marginally attached, have given a job-market related reason for not looking currently for a job. Persons employed part time for economic reasons are those who want and are available for full-time work but have had to settle for a part-time schedule. For more information, see "BLS introduces new range of alternative unemployment measures," in the October 1995 issue of the Monthly Labor Review. Updated population controls are introduced annually with the release of January data.

Table A-13. Persons not in the labor force and multiple jobholders by sex, not seasonally adjusted

(Numbers in thousands)

Category	Total		Men		Women	
	July 2008	July 2009	July 2008	July 2009	July 2008	July 2009
NOT IN THE LABOR FORCE						
Total not in the labor force	77,564	79,614	29,040	30,798	48,523	48,816
Persons who currently want a job	5,213	6,244	2,251	2,793	2,961	3,451
Marginally attached to the labor force [1]	1,573	2,282	810	1,138	764	1,144
Reason not currently looking:						
Discouragement over job prospects [2]	461	796	301	476	160	320
Reasons other than discouragement [3]	1,112	1,486	508	663	604	823
MULTIPLE JOBHOLDERS						
Total multiple jobholders [4]	7,743	7,282	3,981	3,529	3,762	3,753
Percent of total employed	5.3	5.2	5.0	4.7	5.5	5.7
Primary job full time, secondary job part time	4,149	3,807	2,267	1,972	1,882	1,835
Primary and secondary jobs both part time	1,783	1,796	622	621	1,161	1,175
Primary and secondary jobs both full time	335	332	209	194	126	138
Hours vary on primary or secondary job	1,426	1,292	859	707	567	585

[1] Data refer to persons who have searched for work during the prior 12 months and were available to take a job during the reference week.

[2] Includes thinks no work available, could not find work, lacks schooling or training, employer thinks too young or old, and other types of discrimination.

[3] Includes those who did not actively look for work in the prior 4 weeks for such reasons as school or family responsibilities, ill health, and transportation problems, as well as a small number for which reason for nonparticipation was not determined.

[4] Includes persons who work part time on their primary job and full time on their secondary job(s), not shown separately.

NOTE: Updated population controls are introduced annually with the release of January data.

ESTABLISHMENT DATA

Table B-1. Employees on nonfarm payrolls by industry sector and selected industry detail

(In thousands)

Industry	Not seasonally adjusted				Seasonally adjusted						
	July 2008	May 2009	June 2009[p]	July 2009[p]	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009[p]	July 2009[p]	Change from: June 2009-July 2009[p]
Total nonfarm	137,050	132,720	132,651	131,318	137,228	133,000	132,481	132,178	131,735	131,488	-247
Total private	115,714	109,736	110,127	109,949	114,691	110,457	109,865	109,573	109,178	108,924	-254
Goods-producing	21,796	19,010	19,069	19,031	21,432	19,520	19,253	19,041	18,818	18,690	-128
Mining and logging	792	723	728	734	777	754	740	731	725	725	0
Logging	57.3	49.2	50.6	51.6	55.8	51.9	51.4	51.3	51.1	50.7	-.4
Mining	734.4	673.7	677.0	682.1	721.3	701.9	689.0	679.6	673.8	674.1	.3
Oil and gas extraction	165.1	166.5	170.8	172.3	162.7	166.9	167.0	168.1	169.1	169.6	.5
Mining, except oil and gas[1]	235.9	221.5	223.8	225.5	227.6	222.8	220.4	219.4	217.7	217.0	-.7
Coal mining	80.1	80.8	80.0	80.2	79.5	83.3	82.4	81.4	80.3	80.1	-.2
Support activities for mining	333.4	285.7	282.4	284.3	331.0	312.2	301.6	292.1	287.0	287.5	.5
Construction	7,505	6,347	6,420	6,437	7,201	6,470	6,367	6,310	6,224	6,148	-76
Construction of buildings	1,708.8	1,443.8	1,460.2	1,465.0	1,655.5	1,481.5	1,461.7	1,451.2	1,428.3	1,411.2	-17.1
Residential building	856.9	702.2	716.8	715.9	827.9	724.2	715.3	705.0	694.6	683.4	-11.2
Nonresidential building	851.9	741.6	743.4	749.1	827.6	757.3	746.4	746.2	733.7	727.8	-5.9
Heavy and civil engineering construction	1,031.8	900.7	908.2	910.2	970.9	907.2	885.5	876.1	860.3	850.2	-10.1
Specialty trade contractors	4,764.6	4,002.8	4,051.4	4,061.7	4,574.6	4,081.4	4,019.6	3,983.1	3,935.3	3,886.9	-48.4
Residential specialty trade contractors	2,113.9	1,749.7	1,774.7	1,784.8	2,020.0	1,770.3	1,739.3	1,736.1	1,713.4	1,697.9	-15.5
Nonresidential specialty trade contractors	2,650.7	2,253.1	2,276.7	2,276.9	2,554.6	2,311.1	2,280.3	2,247.0	2,221.9	2,189.0	-32.9
Manufacturing	13,499	11,940	11,921	11,860	13,454	12,296	12,146	12,000	11,869	11,817	-52
Production workers	9,698	8,367	8,347	8,301	9,672	8,654	8,532	8,409	8,304	8,274	-30
Durable goods	8,504	7,339	7,293	7,242	8,502	7,620	7,490	7,372	7,267	7,235	-32
Production workers	5,997	5,015	4,975	4,939	6,006	5,239	5,130	5,034	4,952	4,942	-10
Wood products	468.0	372.1	371.6	372.3	458.4	388.4	382.4	373.5	366.1	361.1	-5.0
Nonmetallic mineral products	477.4	411.8	413.9	415.1	466.4	417.0	415.5	410.7	405.5	403.4	-2.1
Primary metals	443.7	364.6	357.6	357.8	444.8	386.4	376.2	367.8	359.8	358.0	-1.8
Fabricated metal products	1,529.7	1,315.6	1,307.8	1,295.8	1,528.4	1,370.3	1,344.1	1,325.9	1,308.5	1,294.4	-14.1
Machinery	1,200.0	1,021.2	1,011.7	1,002.3	1,191.1	1,070.5	1,051.4	1,032.0	1,015.1	999.9	-15.2
Computer and electronic products[1]	1,252.6	1,151.9	1,144.2	1,139.1	1,247.3	1,187.1	1,171.1	1,156.1	1,143.0	1,135.6	-7.4
Computer and peripheral equipment	183.3	163.8	163.3	162.5	182.5	173.5	167.8	164.2	163.5	162.8	-.7
Communications equipment	129.1	127.0	126.8	126.6	129.1	128.5	127.8	127.4	126.7	126.4	-.3
Semiconductors and electronic components	434.5	380.5	375.5	371.7	431.9	397.6	389.2	382.8	374.9	370.4	-4.5
Electronic instruments	443.5	426.8	425.6	425.5	441.8	430.9	431.1	427.2	424.5	423.1	-1.4
Electrical equipment and appliances	430.8	376.5	377.2	373.1	428.4	389.7	382.0	378.4	375.6	370.5	-5.1
Transportation equipment[1]	1,590.7	1,335.7	1,322.4	1,308.0	1,625.7	1,400.4	1,365.9	1,335.3	1,310.8	1,338.4	27.6
Motor vehicles and parts[2]	855.8	654.6	640.7	632.1	892.9	702.8	676.8	654.2	632.5	660.7	28.2
Furniture and related products	485.3	395.0	391.9	389.1	483.4	408.8	401.0	394.4	387.8	382.9	-4.9
Miscellaneous manufacturing	625.9	594.5	594.9	589.0	627.9	601.1	600.4	597.4	594.7	591.0	-3.7
Nondurable goods	4,995	4,601	4,628	4,618	4,952	4,676	4,656	4,628	4,602	4,582	-20
Production workers	3,701	3,352	3,372	3,362	3,666	3,415	3,402	3,375	3,352	3,332	-20
Food manufacturing	1,499.2	1,450.3	1,472.9	1,489.0	1,478.1	1,464.4	1,474.9	1,471.7	1,470.6	1,469.7	-.9
Beverages and tobacco products	205.8	189.6	193.7	194.6	200.0	191.6	190.9	190.5	189.9	189.2	-.7
Textile mills	148.5	126.7	125.0	121.6	149.0	128.2	127.3	126.1	123.9	121.9	-2.0
Textile product mills	146.3	125.9	126.6	125.4	146.2	129.3	127.5	127.0	126.5	125.7	-.8
Apparel	200.6	170.1	167.5	167.2	199.5	173.8	169.9	170.2	165.8	166.8	1.0
Leather and allied products	32.6	31.6	31.0	30.1	33.0	31.7	31.7	31.5	31.0	31.5	.5
Paper and paper products	450.8	409.0	411.7	411.0	447.1	418.3	415.1	410.5	409.0	406.2	-2.8
Printing and related support activities	592.0	527.6	524.8	518.1	591.5	541.5	534.4	529.6	523.2	518.4	-4.8
Petroleum and coal products	121.9	115.7	117.4	117.6	118.1	114.5	114.6	114.5	114.2	113.7	-.5
Chemicals	856.2	813.5	816.9	813.9	850.0	823.4	818.9	814.9	811.8	809.2	-2.6
Plastics and rubber products	741.5	640.5	640.6	629.7	739.3	659.0	651.1	641.4	636.4	629.3	-7.1

See footnotes at the end of table.

ESTABLISHMENT DATA

Table B-1. Employees on nonfarm payrolls by industry sector and selected industry detail—Continued

(In thousands)

Industry	Not seasonally adjusted				Seasonally adjusted						
	July 2008	May 2009	June 2009p	July 2009p	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009p	July 2009p	Change from: June 2009-July 2009p
Service-providing	115,254	113,710	113,582	112,287	115,796	113,480	113,228	113,137	112,917	112,798	-119
Private service-providing	93,918	90,726	91,058	90,918	93,259	90,937	90,612	90,532	90,360	90,234	-126
Trade, transportation, and utilities	26,432	25,235	25,320	25,194	26,425	25,479	25,371	25,308	25,263	25,176	-87
Wholesale trade	6,000.8	5,698.0	5,714.3	5,698.5	5,966.9	5,741.3	5,710.8	5,695.7	5,681.7	5,663.1	-18.6
Durable goods	3,080.7	2,856.4	2,859.1	2,847.7	3,062.5	2,899.4	2,875.5	2,861.8	2,846.6	2,831.3	-15.3
Nondurable goods	2,066.4	2,004.3	2,011.8	2,007.3	2,053.2	2,002.5	1,997.7	1,996.6	1,995.6	1,993.0	-2.6
Electronic markets and agents and brokers	853.7	837.3	843.4	843.5	851.2	839.4	837.6	837.3	839.5	838.8	-.7
Retail trade	15,381.0	14,735.9	14,790.3	14,746.6	15,380.2	14,872.4	14,839.7	14,811.6	14,791.0	14,746.9	-44.1
Motor vehicle and parts dealers[1]	1,872.3	1,688.6	1,692.7	1,694.0	1,851.4	1,701.8	1,690.2	1,681.6	1,673.5	1,668.3	-5.2
Automobile dealers	1,200.7	1,051.5	1,051.6	1,051.6	1,191.5	1,067.7	1,057.1	1,050.2	1,043.0	1,038.7	-4.3
Furniture and home furnishings stores	539.6	479.4	478.7	478.5	545.8	497.7	492.4	486.3	484.6	482.6	-2.0
Electronics and appliance stores	546.0	507.8	506.7	507.2	553.0	518.6	518.0	517.0	515.2	513.2	-2.0
Building material and garden supply stores	1,282.8	1,240.0	1,236.8	1,209.7	1,244.1	1,193.5	1,189.3	1,186.3	1,182.0	1,176.0	-6.0
Food and beverage stores	2,881.0	2,823.1	2,851.4	2,843.1	2,863.4	2,827.6	2,828.9	2,828.0	2,830.4	2,826.8	-3.6
Health and personal care stores	1,001.4	982.2	987.7	984.0	1,005.4	985.0	984.2	984.7	984.7	986.3	1.6
Gasoline stations	854.8	830.4	838.8	843.1	843.0	830.4	831.1	829.0	829.4	829.9	.5
Clothing and clothing accessories stores	1,488.2	1,380.4	1,395.1	1,412.8	1,483.6	1,433.4	1,432.7	1,426.8	1,422.7	1,415.3	-7.4
Sporting goods, hobby, book, and music stores	620.8	589.1	586.5	579.9	642.2	610.0	608.8	607.0	605.0	603.2	-1.8
General merchandise stores[1]	3,022.8	3,002.7	3,007.7	2,993.6	3,062.3	3,045.5	3,041.2	3,041.8	3,043.2	3,033.7	-9.5
Department stores	1,528.7	1,488.2	1,490.4	1,486.8	1,563.2	1,530.9	1,524.0	1,526.0	1,524.7	1,517.1	-7.6
Miscellaneous store retailers	850.6	807.6	806.4	799.5	848.3	810.4	805.3	805.8	803.3	796.2	-7.1
Nonstore retailers	420.7	404.6	401.8	401.2	437.7	418.5	417.6	417.3	417.0	415.4	-1.6
Transportation and warehousing	4,485.9	4,234.0	4,242.7	4,178.5	4,518.0	4,295.5	4,251.7	4,233.5	4,221.9	4,199.5	-22.4
Air transportation	495.8	466.7	471.9	472.4	492.9	474.0	466.8	466.7	468.3	467.8	-.5
Rail transportation	230.7	214.5	213.3	213.6	230.1	220.7	217.9	214.6	212.9	212.0	-.9
Water transportation	69.4	57.3	57.9	57.3	66.4	59.6	58.1	57.2	56.1	54.8	-1.3
Truck transportation	1,406.1	1,271.2	1,287.8	1,284.8	1,391.2	1,300.3	1,283.2	1,277.4	1,269.9	1,263.1	-6.8
Transit and ground passenger transportation	361.2	424.3	411.7	350.9	420.8	406.2	401.8	405.4	412.6	409.8	-2.8
Pipeline transportation	43.2	42.5	42.4	42.1	42.7	43.0	43.0	42.5	42.1	41.5	-.6
Scenic and sightseeing transportation	36.1	29.8	32.9	36.6	27.6	27.0	27.2	28.5	27.8	28.6	.8
Support activities for transportation	594.6	542.8	537.1	534.2	592.8	554.6	550.3	545.6	537.3	532.8	-4.5
Couriers and messengers	574.5	547.3	548.6	545.8	577.7	558.5	556.0	550.5	551.3	548.8	-2.5
Warehousing and storage	674.3	637.6	639.1	640.8	675.8	651.6	647.4	645.1	643.6	640.3	-3.3
Utilities	564.4	567.4	572.6	570.5	559.7	570.1	568.5	567.5	568.2	566.7	-1.5
Information	3,005	2,865	2,862	2,841	2,995	2,905	2,884	2,858	2,840	2,824	-16
Publishing industries, except Internet	886.1	805.6	802.2	796.3	882.9	827.8	820.1	808.6	801.6	793.9	-7.7
Motion picture and sound recording industries	386.6	388.8	394.6	390.6	380.1	393.7	389.5	381.3	379.0	379.0	.0
Broadcasting, except Internet	316.8	292.9	292.0	290.0	315.9	299.0	296.3	294.2	292.0	290.8	-1.2
Telecommunications	1,022.8	987.1	983.2	978.0	1,022.8	996.7	989.3	986.4	980.9	975.7	-5.2
Data processing, hosting and related services	259.6	256.3	255.8	254.5	260.5	253.9	255.5	253.8	254.1	253.7	-.4
Other information services	133.5	134.0	134.1	131.1	133.0	134.1	133.7	133.2	132.8	131.2	-1.6
Financial activities	8,231	7,766	7,801	7,806	8,154	7,857	7,811	7,784	7,755	7,742	-13
Finance and insurance	6,046.7	5,771.1	5,774.8	5,768.2	6,019.9	5,829.5	5,799.6	5,781.6	5,762.0	5,749.1	-12.9
Monetary authorities - central bank	22.6	20.4	20.3	20.4	22.3	20.8	20.5	20.3	20.2	20.2	.0
Credit intermediation and related activities[1]	2,743.9	2,608.5	2,607.6	2,609.1	2,730.9	2,635.4	2,619.8	2,613.5	2,602.8	2,600.6	-2.2
Depository credit intermediation[1]	1,830.4	1,771.1	1,775.1	1,776.2	1,820.0	1,783.4	1,778.0	1,774.4	1,772.6	1,769.7	-2.9
Commercial banking	1,368.8	1,324.8	1,327.3	1,326.9	1,361.1	1,334.2	1,329.4	1,327.9	1,324.5	1,323.1	-1.4
Securities, commodity contracts, investments	863.4	788.8	787.1	785.1	860.4	805.8	797.0	791.7	784.6	780.2	-4.4
Insurance carriers and related activities	2,326.3	2,266.4	2,270.6	2,265.8	2,316.1	2,279.4	2,274.3	2,268.3	2,265.2	2,260.4	-4.8
Funds, trusts, and other financial vehicles	90.5	87.0	89.2	87.8	90.2	88.1	88.0	87.8	89.2	87.7	-1.5
Real estate and rental and leasing	2,184.5	1,994.6	2,026.3	2,037.8	2,134.4	2,027.0	2,011.7	2,002.7	1,993.3	1,993.1	-.2
Real estate	1,510.9	1,399.0	1,418.5	1,425.0	1,481.5	1,421.9	1,411.9	1,405.1	1,397.6	1,397.2	-.4
Rental and leasing services	644.3	567.4	579.6	584.3	624.4	576.6	571.5	569.2	567.7	568.0	.3
Lessors of nonfinancial intangible assets	29.3	28.2	28.2	28.5	28.5	28.5	28.3	28.4	28.0	27.9	-.1

See footnotes at the end of table.

 ESTABLISHMENT DATA

Table B-1. Employees on nonfarm payrolls by industry sector and selected industry detail—Continued

(In thousands)

Industry	Not seasonally adjusted				Seasonally adjusted						
	July 2008	May 2009	June 2009[p]	July 2009[p]	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009[p]	July 2009[p]	Change from: June 2009-July 2009[p]
Professional and business services	17,918	16,728	16,755	16,763	17,788	16,910	16,783	16,756	16,650	16,612	-38
Professional and technical services[1]	7,817.8	7,572.0	7,583.5	7,591.4	7,833.6	7,697.9	7,670.7	7,652.4	7,617.3	7,610.0	-7.3
Legal services	1,177.6	1,132.6	1,145.9	1,143.0	1,163.0	1,144.9	1,139.4	1,136.9	1,131.5	1,128.8	-2.7
Accounting and bookkeeping services	870.4	882.7	870.0	871.4	947.5	929.5	929.3	938.0	936.3	940.3	4.0
Architectural and engineering services	1,475.2	1,345.7	1,350.5	1,345.7	1,449.2	1,377.9	1,364.1	1,350.3	1,336.4	1,322.9	-13.5
Computer systems design and related services	1,459.6	1,450.5	1,452.4	1,465.3	1,456.2	1,459.2	1,460.4	1,457.0	1,456.4	1,464.3	7.9
Management and technical consulting services	1,017.3	1,013.1	1,015.7	1,023.5	1,011.3	1,016.0	1,016.7	1,017.9	1,016.7	1,017.6	.9
Management of companies and enterprises	1,907.6	1,827.4	1,827.8	1,825.9	1,895.3	1,852.6	1,840.2	1,829.9	1,818.9	1,810.8	-8.1
Administrative and waste services	8,192.4	7,328.8	7,343.3	7,345.7	8,058.6	7,359.4	7,272.3	7,274.0	7,213.6	7,191.5	-22.1
Administrative and support services[1]	7,825.6	6,967.7	6,978.5	6,976.7	7,699.3	6,999.2	6,911.7	6,912.7	6,853.0	6,829.6	-23.4
Employment services[1]	3,149.6	2,485.7	2,478.5	2,472.2	3,146.9	2,567.0	2,506.4	2,501.9	2,466.2	2,440.6	-25.6
Temporary help services	2,348.5	1,766.1	1,756.7	1,759.2	2,349.1	1,835.4	1,781.5	1,780.6	1,749.2	1,739.4	-9.8
Business support services	808.2	785.4	774.4	778.3	817.4	799.1	792.9	790.5	784.6	788.7	4.1
Services to buildings and dwellings	1,973.8	1,861.0	1,887.6	1,888.0	1,848.6	1,791.5	1,778.7	1,786.1	1,773.5	1,771.2	-2.3
Waste management and remediation services	366.8	361.1	364.8	369.0	359.3	360.2	360.6	361.3	360.6	361.9	1.3
Education and health services	18,572	19,281	19,088	18,964	18,888	19,158	19,175	19,215	19,252	19,269	17
Educational services	2,757.3	3,116.6	2,902.3	2,792.5	3,062.4	3,077.9	3,077.4	3,077.6	3,090.0	3,089.1	-.9
Health care and social assistance	15,814.4	16,164.6	16,185.4	16,171.3	15,825.9	16,080.1	16,097.8	16,137.7	16,162.1	16,179.4	17.3
Health care[3]	13,367.0	13,568.3	13,634.6	13,666.3	13,329.4	13,535.9	13,553.6	13,581.1	13,606.1	13,625.7	19.6
Ambulatory health care services[1]	5,682.9	5,813.3	5,844.3	5,852.9	5,676.3	5,779.8	5,794.1	5,812.9	5,829.3	5,838.9	9.6
Offices of physicians	2,274.3	2,310.6	2,322.1	2,330.0	2,272.7	2,308.0	2,310.5	2,314.6	2,320.6	2,326.8	6.2
Outpatient care centers	535.7	538.9	543.5	540.4	535.4	537.7	538.7	539.3	542.8	539.7	-3.1
Home health care services	963.1	1,016.7	1,022.7	1,026.1	961.1	996.7	1,004.5	1,013.3	1,017.9	1,021.5	3.6
Hospitals	4,670.4	4,706.5	4,727.4	4,743.5	4,646.8	4,715.1	4,716.7	4,719.1	4,722.1	4,726.3	4.2
Nursing and residential care facilities[1]	3,013.7	3,048.5	3,062.9	3,069.9	3,006.3	3,041.0	3,042.8	3,049.1	3,054.7	3,060.5	5.8
Nursing care facilities	1,613.8	1,626.8	1,632.6	1,632.1	1,612.3	1,621.8	1,624.5	1,626.8	1,628.4	1,627.7	-.7
Social assistance[1]	2,447.4	2,596.3	2,550.8	2,505.0	2,496.5	2,544.2	2,544.2	2,556.6	2,556.0	2,553.7	-2.3
Child day care services	791.3	888.0	839.8	788.7	844.6	858.2	853.9	860.3	852.2	844.7	-7.5
Leisure and hospitality	14,153	13,416	13,740	13,854	13,473	13,202	13,168	13,195	13,177	13,186	9
Arts, entertainment, and recreation	2,268.9	1,982.2	2,124.9	2,191.5	1,966.6	1,928.7	1,900.6	1,901.8	1,883.6	1,893.6	10.0
Performing arts and spectator sports	435.5	416.9	414.8	424.9	406.9	400.5	392.9	396.8	392.2	398.6	6.4
Museums, historical sites, zoos, and parks	147.1	137.6	142.5	144.3	132.1	130.6	130.5	130.9	130.5	129.9	-.6
Amusements, gambling, and recreation	1,686.3	1,427.7	1,567.6	1,622.3	1,427.6	1,397.6	1,377.2	1,374.1	1,360.9	1,365.1	4.2
Accommodation and food services	11,884.5	11,433.5	11,614.6	11,662.5	11,506.3	11,273.2	11,267.0	11,293.6	11,293.6	11,292.1	-1.5
Accommodation	2,000.5	1,720.3	1,803.5	1,860.0	1,854.6	1,732.7	1,723.6	1,728.7	1,726.9	1,727.8	.9
Food services and drinking places	9,884.0	9,713.2	9,811.1	9,802.5	9,651.7	9,540.5	9,543.4	9,564.9	9,566.7	9,564.3	-2.4
Other services	5,607	5,435	5,492	5,496	5,536	5,426	5,420	5,416	5,423	5,425	2
Repair and maintenance	1,239.6	1,166.1	1,169.4	1,164.9	1,230.6	1,166.3	1,163.7	1,158.4	1,156.7	1,155.6	-1.1
Personal and laundry services	1,339.0	1,305.9	1,316.4	1,309.5	1,328.9	1,302.4	1,297.3	1,293.3	1,300.2	1,300.2	.0
Membership associations and organizations	3,028.0	2,962.8	3,006.5	3,021.5	2,976.6	2,956.8	2,958.6	2,964.3	2,965.8	2,969.1	3.3
Government	21,336	22,984	22,524	21,369	22,537	22,543	22,616	22,605	22,557	22,564	7
Federal	2,798	2,857	2,832	2,860	2,776	2,808	2,876	2,860	2,819	2,831	12
Federal, except U.S. Postal Service	2,043.5	2,151.7	2,131.4	2,147.9	2,020.2	2,086.0	2,154.6	2,150.2	2,111.9	2,120.1	8.2
U.S. Postal Service	754.2	705.2	700.9	711.9	755.8	721.7	721.0	709.5	706.8	710.9	4.1
State government	4,902	5,236	4,971	4,892	5,184	5,186	5,189	5,189	5,176	5,171	-5
State government education	2,056.9	2,425.8	2,147.8	2,076.8	2,365.1	2,379.9	2,385.5	2,386.2	2,381.1	2,386.7	5.6
State government, excluding education	2,844.7	2,809.9	2,823.1	2,815.5	2,819.1	2,805.9	2,803.5	2,802.5	2,795.1	2,783.8	-11.3
Local government	13,636	14,891	14,721	13,617	14,577	14,549	14,551	14,556	14,562	14,562	0
Local government education	6,923.6	8,428.4	8,087.8	6,899.8	8,088.3	8,078.7	8,081.4	8,078.0	8,085.8	8,069.1	-16.7
Local government, excluding education	6,712.3	6,462.2	6,633.6	6,716.8	6,488.2	6,469.8	6,469.2	6,478.3	6,476.2	6,493.0	16.8

[1] Includes other industries, not shown separately.
[2] Includes motor vehicles, motor vehicle bodies and trailers, and motor vehicle parts.
[3] Includes ambulatory health care services, hospitals, and nursing and residential care facilities.
[p] = preliminary.

 ESTABLISHMENT DATA

Table B-2. Average weekly hours of production and nonsupervisory workers[1] on private nonfarm payrolls by industry sector and selected industry detail

Industry	Not seasonally adjusted				Seasonally adjusted						
	July 2008	May 2009	June 2009p	July 2009p	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009p	July 2009p	Change from: June 2009-July 2009p
Total private	33.7	33.0	33.1	33.2	33.6	33.1	33.1	33.1	33.0	33.1	0.1
Goods-producing	40.3	39.0	39.3	39.4	40.3	38.9	39.0	39.0	39.0	39.2	.2
Mining and logging	44.8	42.9	43.6	42.7	44.8	43.4	43.0	43.3	43.1	42.7	-.4
Construction	39.2	38.0	38.2	38.7	38.7	37.7	37.5	37.6	37.6	37.8	.2
Manufacturing	40.6	39.3	39.7	39.6	41.0	39.4	39.6	39.4	39.5	39.8	.3
Overtime hours	3.7	2.7	2.9	2.9	3.7	2.6	2.7	2.8	2.9	2.9	.0
Durable goods	40.8	39.2	39.7	39.6	41.2	39.3	39.5	39.4	39.4	39.8	.4
Overtime hours	3.6	2.5	2.6	2.6	3.7	2.4	2.5	2.6	2.6	2.7	.1
Wood products	39.3	37.1	38.7	38.7	38.8	36.9	37.0	36.9	37.5	37.7	.2
Nonmetallic mineral products	42.9	40.6	41.4	42.5	42.6	39.9	40.2	40.5	40.8	41.5	.7
Primary metals	42.1	39.8	40.0	39.8	42.2	40.1	40.0	40.0	39.6	40.1	.5
Fabricated metal products	40.9	39.0	39.3	39.0	41.2	39.0	39.2	39.2	39.2	39.3	.1
Machinery	41.8	39.6	39.7	39.6	42.1	40.1	40.1	39.9	39.8	40.0	.2
Computer and electronic products	40.8	39.8	40.2	39.7	41.1	39.9	40.2	40.0	39.9	40.0	.1
Electrical equipment and appliances	40.4	39.2	39.3	38.5	40.8	38.8	39.6	39.3	39.1	38.9	-.2
Transportation equipment	41.2	39.9	40.7	40.7	42.6	40.0	40.6	40.0	40.4	41.6	1.2
Motor vehicles and parts[2]	40.1	37.9	39.3	39.4	42.0	38.0	39.0	38.0	38.9	40.5	1.6
Furniture and related products	38.4	37.7	38.2	38.0	38.3	37.7	37.6	37.8	37.8	37.9	.1
Miscellaneous manufacturing	38.7	38.0	38.1	38.2	39.1	38.2	38.3	38.0	37.9	38.3	.4
Nondurable goods	40.3	39.4	39.7	39.7	40.6	39.4	39.6	39.6	39.6	39.8	.2
Overtime hours	3.8	3.1	3.3	3.2	3.7	3.0	3.1	3.2	3.3	3.2	-.1
Food manufacturing	40.5	40.0	40.0	39.7	40.6	40.1	40.1	40.0	39.9	39.6	-.3
Beverages and tobacco products	39.0	37.0	35.7	36.0	38.7	36.2	35.8	36.5	35.4	35.7	.3
Textile mills	38.9	36.5	38.2	37.5	39.2	36.3	36.9	36.8	37.9	37.6	-.3
Textile product mills	39.2	38.1	38.4	38.0	39.1	37.0	37.5	38.3	37.7	38.1	.4
Apparel	36.7	36.2	35.7	36.1	37.0	36.1	36.1	36.1	35.5	36.2	.7
Leather and allied products	37.8	32.2	32.0	33.7	38.2	32.8	32.4	32.0	31.9	33.8	1.9
Paper and paper products	42.3	40.9	41.8	42.1	42.6	41.1	41.4	41.2	41.9	42.4	.5
Printing and related support activities	37.5	37.2	37.7	37.5	38.0	37.5	37.7	37.6	38.0	38.0	.0
Petroleum and coal products	46.0	43.0	43.8	43.7	45.5	44.3	43.8	43.4	43.3	42.7	-.6
Chemicals	41.7	40.7	41.4	41.6	41.9	40.9	41.0	41.1	41.2	41.7	.5
Plastics and rubber products	40.8	39.5	40.2	40.0	41.3	39.4	39.8	39.8	39.9	40.4	.5
Private service-providing	32.4	31.9	31.9	32.1	32.3	32.1	32.0	32.0	31.9	32.0	.1
Trade, transportation, and utilities	33.3	32.8	32.8	33.1	33.2	32.7	32.8	32.9	32.8	32.9	.1
Wholesale trade	38.3	37.5	37.6	37.4	38.4	37.8	37.8	37.6	37.6	37.5	-.1
Retail trade	30.3	29.9	29.9	30.4	30.0	29.7	29.8	29.9	29.8	29.9	.1
Transportation and warehousing	36.4	35.7	35.8	36.4	36.4	35.7	35.8	36.0	35.8	36.3	.5
Utilities	42.3	42.1	41.9	41.7	42.4	42.4	42.3	42.1	41.9	41.9	.0
Information	36.8	36.0	36.1	36.5	36.7	36.7	36.4	36.5	36.4	36.5	.1
Financial activities	35.6	35.7	35.7	35.8	35.7	36.1	36.0	36.0	35.9	36.0	.1
Professional and business services	34.7	34.6	34.7	34.4	34.8	34.7	34.7	34.7	34.6	34.5	-.1
Education and health services	32.6	32.1	32.1	32.4	32.5	32.4	32.3	32.3	32.2	32.3	.1
Leisure and hospitality	25.8	24.7	24.9	25.3	25.2	24.8	24.8	24.7	24.6	24.7	.1
Other services	30.9	30.4	30.3	30.4	30.8	30.5	30.5	30.5	30.3	30.3	.0

[1] Data relate to production workers in mining and logging and manufacturing, construction workers in construction, and nonsupervisory workers in the service-providing industries. These groups account for approximately four-fifths of the total employment on private nonfarm payrolls.

[2] Includes motor vehicles, motor vehicle bodies and trailers, and motor vehicle parts.

p = preliminary.

ESTABLISHMENT DATA

Table B-3. Average hourly and weekly earnings of production and nonsupervisory workers[1] on private nonfarm payrolls by industry sector and selected industry detail

Industry	Average hourly earnings				Average weekly earnings			
	July 2008	May 2009	June 2009p	July 2009p	July 2008	May 2009	June 2009p	July 2009p
Total private	$18.02	$18.47	$18.42	$18.46	$607.27	$609.51	$609.70	$612.87
Seasonally adjusted	18.10	18.53	18.53	18.56	608.16	613.34	611.49	614.34
Goods-producing	19.39	19.83	19.84	19.98	781.42	773.37	779.71	787.21
Mining and logging	22.45	23.10	22.99	22.97	1,005.76	990.99	1,002.36	980.82
Construction	21.90	22.54	22.48	22.71	858.48	856.52	858.74	878.88
Manufacturing	17.73	18.09	18.13	18.19	719.84	710.94	719.76	720.32
Durable goods	18.66	19.20	19.22	19.33	761.33	752.64	763.03	765.47
Wood products	14.25	14.91	14.85	14.98	560.03	553.16	574.70	579.73
Nonmetallic mineral products	16.93	17.25	17.30	17.44	726.30	700.35	716.22	741.20
Primary metals	20.43	19.80	19.96	20.52	860.10	788.04	798.40	816.70
Fabricated metal products	16.94	17.38	17.43	17.44	692.85	677.82	685.00	680.16
Machinery	17.96	18.36	18.24	18.35	750.73	727.06	724.13	726.66
Computer and electronic products	21.11	21.70	21.70	21.97	861.29	863.66	872.34	872.21
Electrical equipment and appliances	15.85	16.15	16.18	16.19	640.34	633.08	635.87	623.32
Transportation equipment	23.75	24.85	25.00	24.99	978.50	991.52	1,017.50	1,017.09
Furniture and related products	14.52	15.02	15.13	15.29	557.57	566.25	577.97	581.02
Miscellaneous manufacturing	15.35	16.18	16.06	16.15	594.05	614.84	611.89	616.93
Nondurable goods	16.20	16.43	16.51	16.52	652.86	647.34	655.45	655.84
Food manufacturing	14.03	14.26	14.34	14.32	568.22	570.40	573.60	568.50
Beverages and tobacco products	19.02	20.38	20.21	20.06	741.78	754.06	721.50	722.16
Textile mills	13.77	13.63	13.63	13.43	535.65	497.50	520.67	503.63
Textile product mills	11.80	11.34	11.33	10.97	462.56	432.05	435.07	416.86
Apparel	11.35	11.28	11.40	11.42	416.55	408.34	406.98	412.26
Leather and allied products	12.85	13.85	14.08	13.55	485.73	445.97	450.56	456.64
Paper and paper products	19.11	19.09	19.29	19.51	808.35	780.78	806.32	821.37
Printing and related support activities	16.81	16.61	16.61	16.52	630.38	617.89	626.20	619.50
Petroleum and coal products	27.54	29.18	29.41	30.08	1,266.84	1,254.74	1,288.16	1,314.50
Chemicals	19.41	20.16	20.22	20.42	809.40	820.51	837.11	849.47
Plastics and rubber products	15.87	16.09	16.02	15.84	647.50	635.56	644.00	633.60
Private service-providing	17.68	18.18	18.10	18.13	572.83	579.94	577.39	581.97
Trade, transportation, and utilities	16.18	16.40	16.34	16.39	538.79	537.92	535.95	542.51
Wholesale trade	20.12	20.78	20.66	20.87	770.60	779.25	776.82	780.54
Retail trade	12.92	12.99	12.96	12.99	391.48	388.40	387.50	394.90
Transportation and warehousing	18.54	18.54	18.54	18.60	674.86	661.88	663.73	677.04
Utilities	28.49	29.50	29.20	29.42	1,205.13	1,241.95	1,223.48	1,226.81
Information	24.75	25.41	25.30	25.21	910.80	914.76	913.33	920.17
Financial activities	20.19	20.72	20.67	20.63	718.76	739.70	737.92	738.55
Professional and business services	21.06	22.15	22.09	22.18	730.78	766.39	766.52	762.99
Education and health services	18.96	19.29	19.32	19.44	618.10	619.21	620.17	629.86
Leisure and hospitality	10.73	10.99	10.90	10.91	276.83	271.45	271.41	276.02
Other services	16.06	16.29	16.16	16.17	496.25	495.22	489.65	491.57

[1] See footnote 1, table B-2.

p = preliminary.

ESTABLISHMENT DATA

Table B-4. Average hourly earnings of production and nonsupervisory workers[1] on private nonfarm payrolls by industry sector and selected industry detail, seasonally adjusted

Industry	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009[p]	July 2009[p]	Percent change from: June 2009-July 2009 [p]
Total private:							
Current dollars	$18.10	$18.50	$18.50	$18.53	$18.53	$18.56	0.2
Constant (1982) dollars [2]	8.16	8.64	8.65	8.65	8.57	N.A.	([3])
Goods-producing	19.36	19.85	19.82	19.84	19.86	19.95	.5
Mining and logging	22.54	23.33	23.38	23.26	23.30	23.24	-.3
Construction	21.85	22.59	22.55	22.59	22.59	22.68	.4
Manufacturing	17.80	18.10	18.11	18.11	18.14	18.28	.8
Excluding overtime [4]	17.03	17.52	17.51	17.49	17.50	17.64	.8
Durable goods	18.78	19.17	19.18	19.23	19.23	19.46	1.2
Nondurable goods	16.16	16.46	16.49	16.45	16.54	16.53	-.1
Private service-providing	17.79	18.20	18.21	18.24	18.25	18.26	.1
Trade, transportation, and utilities	16.17	16.38	16.38	16.42	16.37	16.41	.2
Wholesale trade	20.15	20.59	20.70	20.87	20.77	20.88	.5
Retail trade	12.88	12.97	12.96	12.97	12.96	12.96	.0
Transportation and warehousing	18.42	18.68	18.62	18.63	18.54	18.58	.2
Utilities	28.67	29.31	29.29	29.45	29.36	29.47	.4
Information	24.87	25.31	25.28	25.41	25.47	25.34	-.5
Financial activities	20.26	20.62	20.64	20.75	20.79	20.74	-.2
Professional and business services	21.19	22.26	22.26	22.26	22.30	22.35	.2
Education and health services	18.92	19.24	19.33	19.34	19.39	19.42	.2
Leisure and hospitality	10.87	10.98	10.97	10.99	10.99	11.03	.4
Other services	16.13	16.23	16.22	16.24	16.23	16.26	.2

[1] See footnote 1, table B-2.
[2] The Consumer Price Index for Urban Wage Earners and Clerical Workers (CPI-W) is used to deflate this series.
[3] Change was -0.9 percent from May 2009 to June 2009, the latest month available.
[4] Derived by assuming that overtime hours are paid at the rate of time and one-half.
N.A. = not available.
[p] = preliminary.

ESTABLISHMENT DATA

Table B-5. Indexes of aggregate weekly hours of production and nonsupervisory workers[1] on private nonfarm payrolls by industry sector and selected industry detail

(2002=100)

Industry	Not seasonally adjusted				Seasonally adjusted						
	July 2008	May 2009	June 2009p	July 2009p	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009p	July 2009p	Percent change from: June 2009-July 2009p
Total private	107.6	99.7	100.4	100.6	106.2	100.7	100.1	99.8	99.1	99.1	0.0
Goods-producing	99.2	81.8	82.7	82.9	97.3	84.1	82.9	81.8	80.7	80.5	-.2
Mining and logging	140.7	120.8	123.7	122.3	137.6	129.6	125.2	123.6	122.3	120.7	-1.3
Construction	114.3	91.8	93.6	95.4	107.5	93.2	90.8	90.1	88.5	87.5	-1.1
Manufacturing	90.4	75.5	76.1	75.4	91.0	78.3	77.5	76.0	75.3	75.6	.4
Durable goods	91.9	73.9	74.2	73.5	93.0	77.3	76.1	74.5	73.3	73.9	.8
Wood products	80.7	59.3	61.9	62.3	77.7	62.0	60.8	59.3	59.3	58.9	-.7
Nonmetallic mineral products	95.9	77.0	78.2	81.0	92.4	76.8	76.8	76.3	75.1	76.3	1.6
Primary metals	87.6	64.9	63.3	62.9	88.2	70.0	67.6	65.8	63.1	63.7	1.0
Fabricated metal products	100.2	80.1	80.1	78.8	101.0	84.2	82.6	81.3	80.0	79.4	-.8
Machinery	102.4	78.9	78.0	77.0	102.4	84.9	82.9	80.3	78.5	77.5	-1.3
Computer and electronic products	101.2	89.3	89.4	87.7	101.9	91.5	91.1	90.0	88.6	88.3	-.3
Electrical equipment and appliances	88.8	74.4	75.0	72.6	89.3	76.7	76.7	75.0	74.3	72.4	-2.6
Transportation equipment	85.6	66.8	67.4	66.8	91.1	71.0	69.7	66.8	66.1	70.5	6.7
Motor vehicles and parts[2]	68.1	47.7	47.9	47.6	75.1	51.9	50.7	47.4	46.5	52.1	12.0
Furniture and related products	75.9	59.0	59.3	58.6	75.3	61.4	59.9	59.2	58.2	57.7	-.9
Miscellaneous manufacturing	87.9	81.5	82.1	80.9	89.4	82.4	82.9	81.8	81.2	81.3	.1
Nondurable goods	87.9	77.8	78.9	78.6	87.7	79.3	79.4	78.7	78.2	78.1	-.1
Food manufacturing	102.1	96.9	98.5	99.1	100.8	98.2	99.1	98.6	98.3	97.4	-.9
Beverages and tobacco products	98.2	86.2	86.1	87.9	93.3	86.7	85.0	86.3	83.2	83.4	.2
Textile mills	47.3	37.0	38.4	36.5	48.3	37.3	37.9	37.2	38.0	37.2	-2.1
Textile product mills	71.3	58.8	59.5	58.5	71.2	58.5	58.4	59.3	58.3	58.9	1.0
Apparel	57.8	47.0	44.9	45.0	57.9	48.4	46.8	46.9	44.2	45.2	2.3
Leather and allied products	68.4	55.9	54.7	55.8	70.9	57.4	57.2	55.6	54.1	59.1	9.2
Paper and paper products	83.8	72.6	75.0	75.3	83.5	74.8	74.9	73.5	74.6	74.9	.4
Printing and related support activities	83.7	73.7	74.2	72.8	84.7	75.9	75.2	74.7	74.6	73.8	-1.1
Petroleum and coal products	109.9	88.3	91.7	93.3	105.0	89.4	90.0	88.9	88.2	87.2	-1.1
Chemicals	96.7	87.6	89.2	88.8	96.2	89.3	88.8	88.2	87.8	88.2	.5
Plastics and rubber products	88.5	71.8	73.1	70.9	89.3	74.3	74.1	72.5	72.0	71.7	-.4
Private service-providing	110.1	104.6	105.0	105.6	108.9	105.5	104.8	104.7	104.1	104.3	.2
Trade, transportation, and utilities	104.3	97.8	98.1	98.5	103.9	98.6	98.4	98.5	97.9	97.8	-.1
Wholesale trade	110.0	101.5	102.0	101.3	109.5	103.3	102.7	101.8	101.4	100.7	-.7
Retail trade	101.4	95.8	96.1	97.4	100.4	96.1	96.2	96.3	95.8	95.8	.0
Transportation and warehousing	107.1	99.2	99.7	99.6	107.9	100.7	100.0	100.0	99.1	100.2	1.1
Utilities	98.8	98.2	98.7	97.9	97.9	99.6	98.9	98.3	97.8	97.5	-.3
Information	101.0	94.2	94.3	94.6	100.3	97.4	96.0	95.3	94.4	94.1	-.3
Financial activities	108.1	102.5	103.2	103.6	107.2	104.9	104.0	103.6	102.9	103.0	.1
Professional and business services	114.8	105.9	106.4	105.6	114.2	107.5	106.7	106.4	105.3	104.7	-.6
Education and health services	114.3	117.2	116.0	116.3	115.9	117.4	117.1	117.4	117.3	117.7	.3
Leisure and hospitality	118.7	107.5	111.2	114.0	110.0	106.1	105.7	105.7	105.1	105.6	.5
Other services	101.7	97.0	97.8	98.4	99.8	97.0	96.9	97.0	96.5	96.5	.0

[1] See footnote 1, table B-2.

[2] Includes motor vehicles, motor vehicle bodies and trailers, and motor vehicle parts.

p = preliminary.

NOTE: The index of aggregate weekly hours are calculated by dividing the current month's estimates of aggregate hours by the corresponding 2002 annual average levels. Aggregate hours estimates are the product of estimates of average weekly hours and production and nonsupervisory worker employment.

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Table B-6. Indexes of aggregate weekly payrolls of production and nonsupervisory workers[1] on private nonfarm payrolls by industry sector and selected industry detail

(2002=100)

Industry	Not seasonally adjusted				Seasonally adjusted						
	July 2008	May 2009	June 2009[p]	July 2009[p]	July 2008	Mar. 2009	Apr. 2009	May 2009	June 2009[p]	July 2009[p]	Percent change from: June 2009-July 2009[p]
Total private	129.6	123.0	123.6	124.1	128.5	124.4	123.7	123.6	122.7	122.9	0.2
Goods-producing	117.8	99.3	100.5	101.4	115.3	102.3	100.6	99.4	98.1	98.3	.2
Mining and logging	183.7	162.3	165.4	163.4	180.4	175.9	170.3	167.2	165.7	163.2	-1.5
Construction	135.1	111.8	113.6	117.0	126.8	113.7	110.5	109.9	107.9	107.2	-.6
Manufacturing	104.8	89.3	90.2	89.7	105.9	92.6	91.8	90.1	89.3	90.4	1.2
Durable goods	107.1	88.5	89.0	88.7	109.0	92.6	91.2	89.5	88.0	89.8	2.0
Nondurable goods	100.6	90.3	92.0	91.8	100.1	92.2	92.5	91.5	91.4	91.3	-.1
Private service-providing	133.5	130.4	130.4	131.2	132.8	131.6	130.8	130.9	130.3	130.5	.2
Trade, transportation, and utilities	120.4	114.5	114.4	115.2	119.9	115.2	115.0	115.4	114.3	114.5	.2
Wholesale trade	130.4	124.2	124.1	124.5	130.0	125.3	125.2	125.1	124.0	123.8	-.2
Retail trade	112.3	106.6	106.8	108.5	110.9	106.9	106.8	107.1	106.4	106.4	.0
Transportation and warehousing	126.0	116.7	117.2	117.5	126.0	119.3	118.2	118.2	116.6	118.1	1.3
Utilities	117.5	121.0	120.3	120.3	117.2	121.8	120.9	120.8	119.9	120.0	.1
Information	123.7	118.5	118.0	118.0	123.5	122.0	120.1	119.9	119.0	118.1	-.8
Financial activities	135.0	131.3	131.9	132.2	134.3	133.8	132.7	132.9	132.3	132.1	-.2
Professional and business services	143.9	139.5	139.9	139.4	144.0	142.4	141.3	140.9	139.7	139.2	-.4
Education and health services	142.5	148.6	147.3	148.6	144.2	148.5	148.8	149.3	149.5	150.2	.5
Leisure and hospitality	144.6	134.2	137.7	141.3	135.8	132.3	131.7	131.9	131.1	132.2	.8
Other services	119.0	115.1	115.2	115.9	117.3	114.7	114.6	114.8	114.1	114.4	.3

[1] See footnote 1, table B-2.
[p] = preliminary.
NOTE: The index of aggregate weekly payrolls are calculated by dividing the current month's estimates of aggregate payrolls by the corresponding 2002 annual average levels. Aggregate payroll estimates are the product of estimates of average hourly earnings, average weekly hours, and production and nonsupervisory worker employment.

ESTABLISHMENT DATA

Table B-7. Diffusion indexes of employment change

(Percent)

Time span	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
	Private nonfarm payrolls, 271 industries [1]											
Over 1-month span:												
2005	52.6	60.1	54.1	58.1	56.8	58.3	58.5	59.2	54.2	55.9	62.7	57.6
2006	64.9	62.2	63.8	59.8	49.1	51.8	59.2	55.4	55.7	56.3	59.4	60.7
2007	53.5	55.5	52.4	49.4	55.9	48.3	50.7	46.5	55.9	57.2	59.4	57.9
2008	42.1	40.6	44.1	41.1	42.6	36.9	37.6	39.1	34.7	33.0	27.1	20.5
2009	22.1	20.8	19.6	21.8	29.3	[p] 28.6	[p] 30.1					
Over 3-month span:												
2005	51.7	57.2	59.0	59.8	57.9	62.0	60.5	62.9	60.3	55.5	56.3	62.7
2006	67.7	68.6	65.1	65.1	60.5	58.9	55.5	57.0	55.0	54.4	59.0	64.2
2007	62.5	54.8	54.2	54.8	54.1	50.4	52.8	48.7	53.3	53.9	58.3	62.5
2008	57.7	44.8	40.2	39.7	37.3	33.6	33.6	32.8	34.9	33.2	26.9	20.8
2009	18.6	14.2	15.1	15.3	20.3	[p] 23.8	[p] 22.3					
Over 6-month span:												
2005	55.4	57.9	58.1	57.0	58.3	60.9	63.1	63.3	61.6	59.6	61.4	62.5
2006	64.6	63.8	67.5	66.2	65.5	66.6	60.3	61.1	57.9	57.9	62.4	59.0
2007	60.3	57.2	60.5	58.3	55.5	56.5	52.8	52.4	56.6	54.4	56.8	59.0
2008	56.6	53.0	50.7	47.4	40.2	33.4	31.0	33.4	30.6	29.0	26.0	24.4
2009	21.6	17.2	15.1	15.3	15.9	[p] 16.4	[p] 17.3					
Over 12-month span:												
2005	60.9	60.9	60.0	59.2	58.3	60.3	61.3	63.3	60.7	59.2	59.8	61.8
2006	67.2	65.5	65.9	62.9	65.5	66.8	64.8	64.4	66.6	65.9	64.9	66.2
2007	63.3	59.4	61.1	59.6	59.2	58.3	56.8	57.2	59.4	58.9	58.1	59.6
2008	54.4	56.1	52.6	49.1	50.2	47.8	43.7	42.3	38.0	37.8	32.3	28.2
2009	24.0	22.0	19.9	18.1	17.5	[p] 17.5	[p] 17.2					
	Manufacturing payrolls, 83 industries [1]											
Over 1-month span:												
2005	36.7	46.4	42.2	46.4	40.4	33.7	41.0	43.4	45.8	47.6	44.6	47.0
2006	57.8	49.4	53.6	47.0	37.3	50.6	49.4	42.2	40.4	42.8	41.0	44.0
2007	44.6	41.0	30.7	24.7	38.0	32.5	43.4	30.7	39.2	42.8	60.8	48.2
2008	30.7	28.9	37.3	32.5	40.4	25.3	25.9	27.7	22.9	18.7	15.1	10.2
2009	6.0	9.6	10.8	16.3	11.4	[p] 13.3	[p] 22.3					
Over 3-month span:												
2005	36.7	43.4	41.0	41.6	35.5	36.1	34.9	36.7	42.2	44.0	38.6	48.8
2006	56.6	57.2	48.2	48.2	44.6	50.0	43.4	45.2	36.7	33.1	35.5	39.2
2007	40.4	33.1	33.1	28.9	29.5	30.1	31.9	28.9	30.7	30.7	39.2	51.2
2008	48.8	33.7	28.3	29.5	26.5	22.9	19.9	16.9	22.3	21.1	15.1	11.4
2009	6.0	3.6	3.6	7.8	8.4	[p] 10.2	[p] 7.8					
Over 6-month span:												
2005	33.7	39.8	38.0	36.1	35.5	34.9	39.8	36.1	36.1	38.0	36.7	39.8
2006	45.2	45.2	50.6	48.8	50.6	50.0	45.2	47.0	43.4	42.2	39.8	34.3
2007	37.3	33.1	29.5	28.9	30.7	34.9	28.9	26.5	29.5	28.3	33.7	38.0
2008	34.3	30.1	37.3	35.5	25.3	20.5	17.5	18.1	16.9	13.3	11.4	9.6
2009	9.0	4.8	4.8	6.0	4.8	[p] 4.8	[p] 7.2					
Over 12-month span:												
2005	45.2	44.0	42.2	41.0	36.7	35.5	32.5	34.3	33.1	33.7	33.7	38.0
2006	44.0	41.0	41.0	39.8	39.8	45.2	42.2	42.8	47.0	48.8	45.8	44.6
2007	39.8	36.7	37.3	30.7	28.9	29.5	30.7	28.9	33.1	28.9	34.3	35.5
2008	27.7	28.9	25.9	25.3	30.7	27.1	24.7	19.3	21.7	21.7	16.9	15.1
2009	8.4	4.8	4.8	4.8	6.0	[p] 6.0	[p] 7.2					

[1] Based on seasonally adjusted data for 1-, 3-, and 6-month spans and unadjusted data for the 12-month span.

[p] = preliminary.

NOTE: Figures are the percent of industries with employment increasing plus one-half of the industries with unchanged employment, where 50 percent indicates an equal balance between industries with increasing and decreasing employment.

EXHIBIT R-17 ADMITTED

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REGIONAL AND STATE EMPLOYMENT AND UNEMPLOYMENT: JUNE 2009

Regional and state unemployment rates were generally higher in June. Thirty-eight states and the District of Columbia recorded over-the-month unemployment rate increases, 5 states registered rate decreases, and 7 states had no rate change, the Bureau of Labor Statistics of the U.S. Department of Labor reported today. Over the year, jobless rates were higher in all 50 states and the District of Columbia. The national unemployment rate, at 9.5 percent, was little changed between May and June, but was up 3.9 percentage points from a year earlier.

In June, nonfarm payroll employment decreased in 39 states and the District of Columbia, increased in 10 states, and was unchanged in 1 state. The largest over-the-month decrease in the level of employment occurred in California (-66,500), followed by Texas (-40,600), Ohio (-33,000), and Michigan (-31,300). Kansas experienced the largest over-the-month percentage decrease in employment (-1.4 percent), followed by New Mexico (-0.9 percent), Michigan (-0.8 percent), and Wyoming (-0.7 percent). The largest over-the-month increases in employment occurred in North Carolina (4,700), Mississippi (4,500), Arkansas (3,400), and Montana (2,700). Montana (+0.6 percent) experienced the largest over-the-month percentage increase in employment, followed by North Dakota (+0.5 percent) and Mississippi (+0.4 percent). Over the year, nonfarm employment decreased in 48 states and the District of Columbia, increased in 1 state, and remained unchanged in 1 state. The largest over-the-year percentage decreases occurred in Michigan (-8.1 percent), Arizona (-7.4 percent), Nevada (-6.2 percent), and Oregon (-5.6 percent). Only North Dakota (+1.6 percent) reported an over-the-year percentage increase, while Alaska remained unchanged.

Publication of Payroll Employment for Small Metropolitan Areas Resumed

Effective with this release, BLS has resumed publication of payroll employment series for 65 small metropolitan areas. See page 3 for additional information.

Regional Unemployment (Seasonally Adjusted)

In June, the Midwest and West reported the highest regional jobless rates, 10.2 percent each. The Northeast recorded the lowest rate, 8.6 percent. Three of the 4 regions registered statistically significant rate changes from the previous month: the Midwest (+0.4 percentage point) and the Northeast and South (+0.3 point each). All four regions experienced significant jobless rate increases from June 2008, the largest of which were in the Midwest and West (+4.2 and +4.1 percentage points, respectively). (See table 1.)

Among the nine geographic divisions, the East North Central and Pacific reported the highest unemployment rates in June, 11.4 and 11.2 percent, respectively. The Pacific rate was the highest on record for that division; the South Atlantic, at 9.8 percent, also posted a series high. (All region, division, and state series begin in 1976.) The West South Central registered the lowest jobless rate, 7.3 percent, in June. Five of the 9 divisions experienced statistically significant over-the-month unemployment rate changes, all of which were increases: the East North Central and Middle Atlantic (+0.4 percentage point each), Mountain and West South Central (+0.3 point each), and South Atlantic (+0.2 point). All nine divisions had significant over-the-year rate increases, with the East North Central and Pacific recording the largest changes (+4.8 and +4.6 percentage points, respectively).

State Unemployment (Seasonally Adjusted)

Michigan again reported the highest jobless rate, 15.2 percent, in June. (The last state to have an unemployment rate of 15.0 percent or higher was West Virginia in March 1984.) The states with the next highest rates were Rhode Island, 12.4 percent; Oregon, 12.2 percent; South Carolina, 12.1 percent; Nevada, 12.0 percent; California, 11.6 percent; Ohio, 11.1 percent; and North Carolina, 11.0 percent. The Nevada, Rhode Island, and South Carolina rates were the highest on record for those states. Florida, at 10.6 percent, Georgia, at 10.1 percent, and Delaware, at 8.4 percent, also posted series highs. North Dakota registered the lowest unemployment rate in June, 4.2 percent. Overall, 12 states and the District of Columbia had significantly higher jobless rates than the U.S. figure of 9.5 percent, 27 states reported measurably lower rates, and 11 states had rates little different from that of the nation. (See tables A and 3 and chart 1.)

Twelve states recorded statistically significant over-the-month unemployment rate increases in June. Michigan reported the largest of these (+1.1 percentage points), followed by Wyoming (+0.9 point) and West Virginia (+0.8 point). Thirty-eight states and the District of Columbia registered June unemployment rates that were not appreciably different from those of a month earlier, though some had changes that were at least as large numerically as the significant changes. (See table B.)

Michigan reported the largest jobless rate increase from a year earlier (+7.1 percentage points), followed by Oregon (+6.3 points). Four additional states recorded rate increases of 5.0 percentage points or more. The remaining 44 states and the District of Columbia had smaller, but also statistically significant, rate increases from June 2008. (See table C.)

Nonfarm Payroll Employment (Seasonally Adjusted)

Between May and June 2009, 14 states experienced statistically significant changes in employment, all of which were decreases. The largest statistically significant decreases occurred in California (-66,500), Texas (-40,600), Ohio (-33,000), and Michigan (-31,300). (See tables D and 5.)

Over the year, 45 states experienced statistically significant changes in employment; 44 had decreases and 1 reported an increase. The largest statistically significant job losses occurred in California (-766,300), Florida (-392,800), Michigan (-337,600), Ohio (-279,000), Illinois (-272,600), and Texas (-266,300). The only statistically significant over-the-year employment increase occurred in North Dakota (+6,000). Three states recorded statistically significant decreases in employment that were less than 15,000: New Hampshire (-13,300), Vermont (-12,300), and Wyoming (-8,000). (See table E.)

The Metropolitan Area Employment and Unemployment release for June is scheduled to be issued on Wednesday, July 29. The Regional and State Employment and Unemployment release for July is scheduled to be issued on Friday, August 21.

Publication of Payroll Employment for Small Metropolitan Areas Resumed

Effective with the release of June 2009 data, BLS has resumed publication of payroll employment series for 65 small metropolitan areas that were discontinued from the establishment survey in March 2008 due to a reduction in funding that resulted from the 2008 Consolidated Appropriations Act enacted on December 26, 2007. The funds to produce these series were restored with the 2009 Omnibus Appropriations Act enacted on March 11, 2009. Publication of metropolitan area hours and earnings series will resume on August 21, 2009, with the release of July 2009 data. The 65 metropolitan areas for which BLS will resume publication of nonfarm employment data are listed on the BLS Web site at http://www.bls.gov/sae/msarestoration.htm.

Table A. States with unemployment rates significantly different from that of the U.S., June 2009, seasonally adjusted

State	Rate [p]
United States [1]	9.5
Alaska	8.4
Arkansas	7.2
California	11.6
Colorado	7.6
Connecticut	8.0
Delaware	8.4
District of Columbia	10.9
Florida	10.6
Hawaii	7.4
Idaho	8.4
Indiana	10.7
Iowa	6.2
Kansas	7.0
Kentucky	10.9
Louisiana	6.8
Maine	8.5
Maryland	7.3
Michigan	15.2
Minnesota	8.4
Montana	6.4
Nebraska	5.0
Nevada	12.0
New Hampshire	6.8
New Mexico	6.8
New York	8.7
North Carolina	11.0
North Dakota	4.2
Ohio	11.1
Oklahoma	6.3
Oregon	12.2
Pennsylvania	8.3
Rhode Island	12.4
South Carolina	12.1
South Dakota	5.1
Tennessee	10.8
Texas	7.5
Utah	5.7
Vermont	7.1
Virginia	7.2
Wyoming	5.9

[1] Data are not preliminary.

[p] = preliminary.

Table B. States with statistically significant unemployment rate changes from May 2009 to June 2009, seasonally adjusted

State	Rate		Over-the-month rate change p
	May 2009	June 2009 p	
Arizona	8.2	8.7	0.5
Florida	10.3	10.6	.3
Georgia	9.6	10.1	.5
Idaho	7.8	8.4	.6
Iowa	5.7	6.2	.5
Massachusetts	8.2	8.6	.4
Michigan	14.1	15.2	1.1
New Jersey	8.8	9.2	.4
New York	8.2	8.7	.5
Texas	7.1	7.5	.4
West Virginia	8.4	9.2	.8
Wyoming	5.0	5.9	.9

p = preliminary.

Table C. States with statistically significant unemployment rate changes from June 2008 to June 2009, seasonally adjusted

State	Rate		Over-the-year rate change p
	June 2008	June 2009 p	
Alabama	4.9	10.1	5.2
Alaska	6.6	8.4	1.8
Arizona	5.5	8.7	3.2
Arkansas	5.0	7.2	2.2
California	7.1	11.6	4.5
Colorado	4.8	7.6	2.8
Connecticut	5.5	8.0	2.5
Delaware	4.6	8.4	3.8
District of Columbia	6.8	10.9	4.1
Florida	6.0	10.6	4.6
Georgia	6.1	10.1	4.0
Hawaii	3.9	7.4	3.5
Idaho	4.7	8.4	3.7
Illinois	6.6	10.3	3.7
Indiana	5.6	10.7	5.1
Iowa	4.1	6.2	2.1
Kansas	4.3	7.0	2.7
Kentucky	6.4	10.9	4.5
Louisiana	4.2	6.8	2.6
Maine	5.2	8.5	3.3
Maryland	4.3	7.3	3.0
Massachusetts	5.1	8.6	3.5
Michigan	8.1	15.2	7.1
Minnesota	5.3	8.4	3.1
Mississippi	6.9	9.0	2.1
Missouri	5.8	9.3	3.5
Montana	4.4	6.4	2.0
Nebraska	3.3	5.0	1.7
Nevada	6.4	12.0	5.6
New Hampshire	3.7	6.8	3.1
New Jersey	5.2	9.2	4.0
New Mexico	4.1	6.8	2.7
New York	5.3	8.7	3.4
North Carolina	6.1	11.0	4.9
North Dakota	3.1	4.2	1.1
Ohio	6.4	11.1	4.7
Oklahoma	3.8	6.3	2.5
Oregon	5.9	12.2	6.3
Pennsylvania	5.3	8.3	3.0
Rhode Island	7.7	12.4	4.7
South Carolina	6.5	12.1	5.6
South Dakota	2.9	5.1	2.2
Tennessee	6.4	10.8	4.4
Texas	4.8	7.5	2.7
Utah	3.3	5.7	2.4
Vermont	4.5	7.1	2.6
Virginia	3.9	7.2	3.3
Washington	5.2	9.3	4.1
West Virginia	4.3	9.2	4.9
Wisconsin	4.4	9.0	4.6
Wyoming	3.2	5.9	2.7

p = preliminary.

Table D. States with statistically significant employment changes from May 2009 to June 2009, seasonally adjusted

State	May 2009	June 2009 p	Over-the-month change p
California	14,351,500	14,285,000	-66,500
Colorado	2,261,800	2,249,300	-12,500
Georgia	3,918,700	3,904,500	-14,200
Kansas	1,355,900	1,336,500	-19,400
Michigan	3,877,100	3,845,800	-31,300
Minnesota	2,665,800	2,649,100	-16,700
New Mexico	826,200	819,000	-7,200
New York	8,605,200	8,582,200	-23,000
Ohio	5,133,200	5,100,200	-33,000
Oregon	1,634,400	1,627,200	-7,200
Tennessee	2,662,200	2,649,900	-12,300
Texas	10,399,300	10,358,700	-40,600
Utah	1,214,700	1,207,900	-6,800
Virginia	3,677,600	3,654,800	-22,800

p = preliminary.

Table E. States with statistically significant employment changes from June 2008 to June 2009, seasonally adjusted

State	June 2008	June 2009 p	Over-the-year change p
Alabama	1,999,500	1,909,800	-89,700
Arizona	2,627,600	2,434,100	-193,500
Arkansas	1,203,500	1,177,100	-26,400
California	15,051,300	14,285,000	-766,300
Colorado	2,353,400	2,249,300	-104,100
Connecticut	1,704,300	1,639,200	-65,100
Delaware	434,000	412,400	-21,600
Florida	7,772,200	7,379,400	-392,800
Georgia	4,118,800	3,904,500	-214,300
Hawaii	619,500	599,900	-19,600
Idaho	650,400	618,400	-32,000
Illinois	5,958,700	5,686,100	-272,600
Indiana	2,968,100	2,815,100	-153,000
Iowa	1,523,000	1,480,000	-43,000
Kansas	1,387,100	1,336,500	-50,600
Kentucky	1,856,500	1,774,200	-82,300
Maine	617,700	598,300	-19,400
Maryland	2,601,200	2,545,000	-56,200
Massachusetts	3,293,800	3,187,400	-106,400
Michigan	4,183,400	3,845,800	-337,600
Minnesota	2,764,500	2,649,100	-115,400
Mississippi	1,151,900	1,120,900	-31,000
Missouri	2,797,000	2,717,800	-79,200
Nevada	1,271,500	1,192,400	-79,100
New Hampshire	646,300	633,000	-13,300
New Jersey	4,066,200	3,931,200	-135,000
New Mexico	847,400	819,000	-28,400
New York	8,802,900	8,582,200	-220,700
North Carolina	4,138,700	3,947,000	-191,700
North Dakota	366,800	372,800	6,000
Ohio	5,379,200	5,100,200	-279,000
Oklahoma	1,590,300	1,559,800	-30,500
Oregon	1,723,500	1,627,200	-96,300
Pennsylvania	5,806,900	5,630,700	-176,200
Rhode Island	482,700	462,900	-19,800
South Carolina	1,942,100	1,851,100	-91,000
Tennessee	2,779,100	2,649,900	-129,200
Texas	10,625,000	10,358,700	-266,300
Utah	1,254,600	1,207,900	-46,700
Vermont	306,300	294,000	-12,300
Virginia	3,761,100	3,654,800	-106,300
Washington	2,963,400	2,858,100	-105,300
West Virginia	758,400	736,300	-22,100
Wisconsin	2,871,900	2,753,500	-118,400
Wyoming	297,500	289,500	-8,000

p = preliminary.

Technical Note

This release presents labor force and unemployment data for census regions and divisions, states, and selected substate areas from the Local Area Unemployment Statistics (LAUS) program (tables 1 to 4). Also presented are nonfarm payroll employment estimates by state and major industry sector from the Current Employment Statistics (CES) program (tables 5 and 6). The LAUS and CES programs are both federal-state cooperative endeavors.

Labor force and unemployment—from the LAUS program

Definitions. The labor force and unemployment data are based on the same concepts and definitions as those used for the official national estimates obtained from the Current Population Survey (CPS), a sample survey of households that is conducted for the Bureau of Labor Statistics (BLS) by the U.S. Census Bureau. The LAUS program measures employment and unemployment on a place-of-residence basis. The universe for each is the civilian noninstitutional population 16 years of age and over. *Employed* persons are those who did any work at all for pay or profit in the reference week (the week including the 12th of the month) or worked 15 hours or more without pay in a family business or farm, plus those not working who had a job from which they were temporarily absent, whether or not paid, for such reasons as labor-management dispute, illness, or vacation. *Unemployed* persons are those who were not employed during the reference week (based on the definition above), had actively looked for a job sometime in the 4-week period ending with the reference week, and were currently available for work; persons on layoff expecting recall need not be looking for work to be counted as unemployed. The *labor force* is the sum of employed and unemployed persons. The *unemployment rate* is the number of unemployed as a percent of the labor force.

Method of estimation. Estimates for 48 of the 50 states, the District of Columbia, the Los Angeles-Long Beach-Glendale metropolitan division, New York City, and the balances of California and New York State are produced using estimating equations based on regression techniques. This method, which underwent substantial enhancement at the beginning of 2005, utilizes data from several sources, including the CPS, the CES, and state unemployment insurance (UI) programs. Estimates for the state of California are derived by summing the estimates for the Los Angeles-Long Beach-Glendale metropolitan division and the balance of California. Similarly, estimates for New York State are derived by summing the estimates for New York City and the balance of New York State. Estimates for all nine census divisions and the five additional substate areas contained in this release (the Cleveland-Elyria-Mentor and Detroit-Warren-Livonia metropolitan areas and the Chicago-Naperville-Joliet, Miami-Miami Beach-Kendall, and Seattle-Bellevue-Everett metropolitan divisions) and their respective balances of state are based on a similar regression approach that does not incorporate CES or UI data. Estimates for census regions are obtained by summing the model-based estimates for the component divisions and then calculating the unemployment rate. Each month, census division estimates are controlled to national totals; state estimates are then controlled to their respective division totals. Substate and balance-of-state estimates for the five areas noted above are controlled to their respective state totals. Estimates for Puerto Rico are derived from a monthly household survey similar to the CPS. A detailed description of the estimation procedures is available from BLS upon request.

Annual revisions. Labor force and unemployment data for prior years reflect adjustments made at the end of each year. The adjusted estimates reflect updated population data from the U.S. Census Bureau, any revisions in the other data sources, and model reestimation. In most years, historical data for the most recent five years (both seasonally adjusted and not seasonally adjusted) are revised near the beginning of each calendar year, prior to or coincident with the release of January estimates.

Seasonal adjustment. Seasonal adjustment of modeled estimates of employment and unemployment levels is performed within the modeling procedure. Series are decomposed into trend, seasonal, and irregular components and survey error. This directly yields seasonally adjusted estimates for employment and unemployment levels with reliability measures. Labor force levels and unemployment rates are calculated from these two estimates.

Area definitions. The substate area data published in this release reflect the standards and definitions established by the U.S. Office of Management and Budget on November 20, 2008. A detailed list of the geographic definitions is available on the Internet at http://www.bls.gov/lau/lausmsa.htm.

Employment—from the CES program

Definitions. Employment data refer to persons on establishment payrolls who receive pay for any part of the pay period that includes the 12th of the month. Persons are counted at their place of work rather than at their place of residence; those appearing on more than one payroll are counted on each payroll. Industries are classified on the basis of their principal activity in accordance with the 2007 version of the North American Industry Classification System.

Method of estimation. The employment data are estimated using a "link relative" technique in which a ratio (link relative) of current-month employment to that of the previous month is computed from a sample of establishments reporting for both months. The estimates of employment for the current month are obtained by multiplying the estimates for the previous month by these ratios. Small-domain models are used as the official estimators for the approximately 44 percent of CES published series which have insufficient sample for direct sample-based estimates.

Annual revisions. Employment estimates are adjusted annually to a complete count of jobs, called benchmarks, derived principally from tax reports that are submitted by employers who are covered under state unemployment insurance (UI) laws. The benchmark information is used to adjust the monthly estimates between the new benchmark and the preceding one and also to establish the level of employment for the new benchmark month. Thus, the benchmarking process establishes the level of employment, and the sample is used to measure the month-to-month changes in the level for the subsequent months.

Seasonal adjustment. Payroll employment data are seasonally adjusted at the statewide supersector level. In some states, the seasonally adjusted payroll employment total is computed by aggregating the independently adjusted supersector series. In other states, the seasonally adjusted payroll employment total is independently adjusted. Revisions of historical data for the most recent 5 years are made once a year, coincident with annual benchmark adjustments.

Caution on aggregating state data. State estimation procedures are designed to produce accurate data for each individual state. BLS independently develops a national employment series; state estimates are not forced to sum to national totals. Because each state series is subject to larger sampling and nonsampling errors than the national series, summing them cumulates individual state level errors and can cause significant distortions at an aggregate level. Due to these statistical limitations, BLS does not compile a "sum-of-states" employment series, and cautions users that such a series is subject to a relatively large and volatile error structure.

Reliability of the estimates

The estimates presented in this release are based on sample surveys, administrative data, and modeling and, thus, are subject to sampling and other types of errors. Sampling error is a measure of sampling variability—that is, variation that occurs by chance because a sample rather than the entire population is surveyed. Survey data also are subject to nonsampling errors, such as those which can be introduced into the data collection and processing operations. Estimates not directly derived from sample surveys are subject to additional errors resulting from the specific estimation processes used. The sums of individual items may not always equal the totals shown in the same tables because of rounding. Unemployment rates are computed from unrounded data and thus may differ slightly from rates computed using the rounded data displayed in the tables.

Use of error measures. In 2005, the LAUS program introduced several improvements to its methodology. Among these was the development of model-based error measures for the monthly estimates and the estimates of over-the-month changes. The introductory section of this release preserves the long-time practice of highlighting the direction of the movements in regional and state unemployment rates and state nonfarm payroll employment regardless of their statistical significance. The remainder of the analysis in the release takes statistical significance into consideration.

Labor force and unemployment estimates. Model-based error measures for both seasonally adjusted and not seasonally adjusted data and for over-the-month changes are available online at http://www.bls.gov/lau/lastderr.htm. BLS uses a 90-percent confidence level in determining whether changes in LAUS unemployment rates are statistically significant. The average magnitude of the current year over-the-month change in a state unemployment rate that is required in order to be statistically significant at the 90-percent confidence level is between 0.3 and 0.4 percentage point. More details can be found on the Web site. Measures of nonsampling error are not available, but additional information on the subject is provided in *Employment and Earnings Online* at http://www.bls.gov/opub/ee/home.htm.

Employment estimates. Measures of sampling error for state CES data at the total nonfarm and supersector level and for metropolitan area CES data at the total nonfarm level are available online at http://www.bls.gov/sae/790stderr.htm. BLS uses a 90-percent confidence level in determining whether changes in CES employment levels are statistically significant. Information on recent benchmark revisions for states is available on the Internet at http://www.bls.gov/sae/.

Additional information

More complete information on the technical procedures used to develop these estimates and additional data appear in *Employment and Earnings Online*.

Estimates of labor force and unemployment from the LAUS program, as well as nonfarm employment from the CES program, for over 300 metropolitan areas and metropolitan New England City and Town Areas (NECTAs) are available in the news release, *Metropolitan Area Employment and Unemployment*. Estimates of labor force, employment, and unemployment for all states, metropolitan areas, labor market areas, counties, cities with a population of 25,000 or more, and other areas used in the administration of various federal economic assistance programs are available on the Internet at http://www.bls.gov/lau/. Employment data from the CES program are available on the Internet at http://www.bls.gov/sae/.

Information in this release will be made available to sensory impaired individuals upon request. Voice phone: (202) 691-5200; TDD message referral phone: 1-800-877-8339.

Table 1. Civilian labor force and unemployment by census region and division, seasonally adjusted [1]

(Numbers in thousands)

Census region and division	Civilian labor force				Unemployed							
					Number				Percent of labor force			
	June 2008	April 2009	May 2009	June 2009	June 2008	April 2009	May 2009	June 2009	June 2008	April 2009	May 2009	June 2009
Northeast	28,210.4	28,468.5	28,503.8	28,418.5	1,482.7	2,250.0	2,370.5	2,456.3	5.3	7.9	8.3	8.6
New England	7,663.2	7,696.4	7,690.4	7,663.5	404.3	617.8	634.6	649.5	5.3	8.0	8.3	8.5
Middle Atlantic	20,547.2	20,772.1	20,813.4	20,755.1	1,078.4	1,632.2	1,735.9	1,806.8	5.2	7.9	8.3	8.7
South	54,883.1	55,184.6	55,161.1	55,129.0	2,925.5	4,627.3	4,899.6	5,045.5	5.3	8.4	8.9	9.2
South Atlantic	29,453.6	29,492.3	29,444.3	29,392.8	1,622.2	2,685.9	2,828.1	2,895.0	5.5	9.1	9.6	9.8
East South Central	8,569.6	8,564.7	8,555.4	8,540.7	527.7	821.1	878.0	891.1	6.2	9.6	10.3	10.4
West South Central	16,859.9	17,127.7	17,161.5	17,195.5	775.6	1,120.3	1,193.5	1,259.4	4.6	6.5	7.0	7.3
Midwest	34,889.9	34,714.6	34,798.9	34,748.2	2,106.3	3,185.9	3,419.4	3,533.2	6.0	9.2	9.8	10.2
East North Central	23,969.3	23,741.3	23,822.2	23,797.6	1,580.8	2,440.2	2,620.3	2,710.6	6.6	10.3	11.0	11.4
West North Central	10,920.6	10,973.3	10,976.8	10,950.7	525.5	745.7	799.1	822.6	4.8	6.8	7.3	7.5
West	35,915.2	36,362.4	36,272.5	36,159.9	2,184.3	3,512.4	3,662.6	3,701.4	6.1	9.7	10.1	10.2
Mountain	11,121.5	11,171.2	11,163.9	11,110.7	546.2	814.1	866.0	901.9	4.9	7.3	7.8	8.1
Pacific	24,793.7	25,191.2	25,108.5	25,049.2	1,638.1	2,698.3	2,796.6	2,799.5	6.6	10.7	11.1	11.2

[1] Census region estimates are derived by summing the Census division model-based estimates.

NOTE: Data refer to place of residence. The States (including the District of Columbia) that compose the various census divisions are: New England: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont; Middle Atlantic: New Jersey, New York, and Pennsylvania; South Atlantic: Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia; East South Central: Alabama, Kentucky, Mississippi, and Tennessee; West South Central: Arkansas, Louisiana, Oklahoma, and Texas; East North Central: Illinois, Indiana, Michigan, Ohio, and Wisconsin; West North Central: Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota; Mountain: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming; and Pacific: Alaska, California, Hawaii, Oregon, and Washington. Estimates for the current year are subject to revision early in the following calendar year.

Table 2. Civilian labor force and unemployment by census region and division, not seasonally adjusted [1]

(Numbers in thousands)

Census region and division	Civilian labor force				Unemployed							
					Number				Percent of labor force			
	May		June		May		June		May		June	
	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009
Northeast	28,122.8	28,370.4	28,507.6	28,719.4	1,390.3	2,310.2	1,484.3	2,479.2	4.9	8.1	5.2	8.6
New England	7,641.6	7,654.3	7,764.5	7,765.1	379.0	619.4	410.6	661.5	5.0	8.1	5.3	8.5
Middle Atlantic	20,481.2	20,716.1	20,743.1	20,954.3	1,011.3	1,690.8	1,073.7	1,817.7	4.9	8.2	5.2	8.7
South	54,909.5	55,106.8	55,378.9	55,650.6	2,725.2	4,787.0	3,081.9	5,255.7	5.0	8.7	5.6	9.4
South Atlantic	29,510.6	29,449.9	29,671.6	29,625.6	1,512.2	2,773.6	1,672.4	2,972.3	5.1	9.4	5.6	10.0
East South Central	8,568.5	8,535.0	8,675.6	8,650.7	489.9	855.4	559.3	932.3	5.7	10.0	6.4	10.8
West South Central	16,830.5	17,121.9	17,031.7	17,374.3	723.0	1,157.9	850.2	1,351.1	4.3	6.8	5.0	7.8
Midwest	34,917.5	34,746.7	35,357.5	35,234.6	1,951.7	3,328.0	2,161.3	3,626.5	5.6	9.6	6.1	10.3
East North Central	23,977.6	23,775.7	24,279.3	24,125.5	1,462.7	2,556.9	1,623.4	2,780.9	6.1	10.8	6.7	11.5
West North Central	10,939.9	10,971.0	11,078.2	11,109.1	489.0	771.1	537.9	845.6	4.5	7.0	4.9	7.6
West	35,776.6	36,112.5	36,058.8	36,316.0	1,993.1	3,548.0	2,188.3	3,733.4	5.6	9.8	6.1	10.3
Mountain	11,071.5	11,115.6	11,198.2	11,190.8	489.9	837.0	560.1	926.5	4.4	7.5	5.0	8.3
Pacific	24,705.1	24,996.9	24,860.6	25,125.2	1,503.2	2,711.0	1,628.2	2,806.9	6.1	10.8	6.5	11.2

[1] Census region estimates are derived by summing the Census division model-based estimates.

NOTE: Data refer to place of residence. The composition of the regions and divisions is described in table 1. Estimates for the current year are subject to revision early in the following calendar year.

LABOR FORCE DATA
SEASONALLY ADJUSTED

Table 3. Civilian labor force and unemployment by state and selected area, seasonally adjusted

(Numbers in thousands)

State and area	Civilian labor force				Unemployed							
					Number				Percent of labor force			
	June 2008	April 2009	May 2009	June 2009p	June 2008	April 2009	May 2009	June 2009p	June 2008	April 2009	May 2009	June 2009p
Alabama	2,163.2	2,131.4	2,128.6	2,128.4	105.2	191.3	208.3	215.6	4.9	9.0	9.8	10.1
Alaska	357.0	358.7	359.2	359.9	23.7	28.3	29.7	30.4	6.6	7.9	8.3	8.4
Arizona	3,127.9	3,153.4	3,152.7	3,145.2	172.2	241.3	258.6	274.2	5.5	7.7	8.2	8.7
Arkansas	1,369.0	1,359.0	1,359.9	1,367.1	67.8	88.7	95.0	98.8	5.0	6.5	7.0	7.2
California	18,381.2	18,629.5	18,540.6	18,494.4	1,296.5	2,065.5	2,152.8	2,146.2	7.1	11.1	11.6	11.6
Los Angeles-Long Beach-Glendale [1]	4,971.2	4,998.5	4,996.6	4,997.0	365.4	545.7	578.3	564.3	7.4	10.9	11.6	11.3
Colorado	2,726.7	2,737.4	2,721.2	2,699.9	130.5	202.5	207.0	204.0	4.8	7.4	7.6	7.6
Connecticut	1,871.9	1,887.2	1,886.5	1,880.7	102.7	148.5	150.4	149.8	5.5	7.9	8.0	8.0
Delaware	442.3	438.3	437.9	437.6	20.3	32.5	35.6	36.9	4.6	7.4	8.1	8.4
District of Columbia	331.9	326.2	329.0	328.4	22.6	32.2	35.2	35.9	6.8	9.9	10.7	10.9
Florida	9,198.5	9,247.9	9,243.7	9,192.1	555.0	893.7	953.6	970.1	6.0	9.7	10.3	10.6
Miami-Miami Beach-Kendall [1]	1,211.5	1,217.1	1,224.6	1,224.0	69.5	100.3	121.5	130.1	5.7	8.2	9.9	10.6
Georgia	4,842.4	4,784.1	4,771.4	4,769.3	293.1	440.2	458.9	483.4	6.1	9.2	9.6	10.1
Hawaii	654.6	646.7	649.2	645.5	25.3	44.9	48.0	47.7	3.9	6.9	7.4	7.4
Idaho	753.7	750.2	750.8	749.2	35.8	52.6	58.6	62.7	4.7	7.0	7.8	8.4
Illinois	6,700.7	6,611.2	6,667.0	6,654.1	440.8	618.6	670.3	683.3	6.6	9.4	10.1	10.3
Chicago-Naperville-Joliet [1]	4,137.2	4,102.8	4,131.3	4,125.4	263.2	396.1	433.1	435.4	6.4	9.7	10.5	10.6
Indiana	3,226.4	3,205.3	3,217.5	3,214.6	181.2	318.7	341.9	343.0	5.6	9.9	10.6	10.7
Iowa	1,674.5	1,674.8	1,678.9	1,682.8	68.4	84.9	95.8	104.1	4.1	5.1	5.7	6.2
Kansas	1,495.1	1,522.0	1,528.4	1,520.9	64.3	98.4	107.3	105.8	4.3	6.5	7.0	7.0
Kentucky	2,040.7	2,076.5	2,077.5	2,077.0	129.8	205.1	221.3	226.1	6.4	9.9	10.7	10.9
Louisiana	2,068.1	2,074.3	2,068.5	2,067.7	86.3	127.9	135.6	140.9	4.2	6.2	6.6	6.8
Maine	706.1	703.9	702.6	701.4	36.4	55.5	58.1	59.9	5.2	7.9	8.3	8.5
Maryland	2,996.1	2,968.4	2,955.0	2,955.9	127.6	200.7	212.4	215.2	4.3	6.8	7.2	7.3
Massachusetts	3,424.1	3,434.3	3,429.9	3,420.2	173.8	274.5	282.0	295.6	5.1	8.0	8.2	8.6
Michigan	4,940.6	4,847.9	4,848.3	4,871.6	402.5	626.6	681.4	740.1	8.1	12.9	14.1	15.2
Detroit-Warren-Livonia [2]	2,109.4	2,104.6	2,101.6	2,087.5	184.6	302.8	322.6	340.8	8.8	14.4	15.3	16.3
Minnesota	2,926.2	2,964.0	2,957.3	2,957.1	154.6	238.4	240.8	249.1	5.3	8.0	8.1	8.4
Mississippi	1,313.9	1,311.9	1,311.2	1,295.5	90.7	119.5	127.3	116.3	6.9	9.1	9.7	9.0
Missouri	3,007.4	3,008.4	3,010.4	2,996.0	175.5	242.5	270.9	278.3	5.8	8.1	9.0	9.3
Montana	505.6	502.7	500.8	499.9	22.5	30.1	31.5	31.9	4.4	6.0	6.3	6.4
Nebraska	994.7	990.5	986.4	984.6	32.6	44.4	47.2	49.1	3.3	4.5	4.8	5.0
Nevada	1,368.7	1,400.5	1,405.6	1,400.5	87.0	148.1	158.0	167.4	6.4	10.6	11.2	12.0
New Hampshire	738.7	744.0	742.0	738.1	27.5	47.0	48.5	50.1	3.7	6.3	6.5	6.8
New Jersey	4,492.6	4,572.4	4,560.4	4,551.8	235.7	384.4	400.0	420.8	5.2	8.4	8.8	9.2
New Mexico	957.8	955.5	958.8	954.0	39.4	55.4	62.4	64.9	4.1	5.8	6.5	6.8
New York	9,680.3	9,772.0	9,771.4	9,777.6	516.2	751.4	799.7	854.2	5.3	7.7	8.2	8.7
New York City	3,947.9	4,004.4	4,025.1	4,031.7	211.8	321.9	359.7	381.2	5.4	8.0	8.9	9.5
North Carolina	4,529.8	4,579.6	4,567.1	4,556.8	277.6	491.4	507.0	502.3	6.1	10.7	11.1	11.0
North Dakota	369.4	369.8	368.3	365.3	11.6	15.1	15.9	15.5	3.1	4.1	4.3	4.2
Ohio	5,971.8	5,968.5	5,979.7	5,968.0	383.1	609.3	646.5	661.7	6.4	10.2	10.8	11.1
Cleveland-Elyria-Mentor [2]	1,081.8	1,070.5	1,076.4	1,071.1	71.5	98.2	108.4	101.6	6.6	9.2	10.1	9.5
Oklahoma	1,748.2	1,771.7	1,771.8	1,776.9	66.7	110.4	112.6	112.1	3.8	6.2	6.4	6.3
Oregon	1,951.3	2,003.6	1,997.7	1,982.1	116.1	236.0	243.6	242.0	5.9	11.8	12.2	12.2
Pennsylvania	6,391.0	6,430.8	6,472.1	6,436.0	336.0	499.5	534.8	537.0	5.3	7.8	8.3	8.3
Rhode Island	567.5	563.4	566.0	569.7	43.5	62.7	68.4	70.7	7.7	11.1	12.1	12.4
South Carolina	2,145.8	2,198.4	2,203.1	2,193.7	139.8	250.2	263.6	265.0	6.5	11.4	12.0	12.1
South Dakota	444.0	446.9	446.4	447.0	12.8	21.6	22.3	22.6	2.9	4.8	5.0	5.1
Tennessee	3,039.2	3,039.1	3,041.3	3,039.1	195.4	300.5	325.3	328.2	6.4	9.9	10.7	10.8
Texas	11,682.5	11,924.8	11,955.4	11,972.6	563.2	793.0	843.4	899.7	4.8	6.6	7.1	7.5
Utah	1,381.3	1,379.4	1,382.4	1,371.5	46.0	71.3	74.9	78.1	3.3	5.2	5.4	5.7
Vermont	354.4	361.0	360.9	358.8	15.9	26.3	26.5	25.4	4.5	7.3	7.4	7.1
Virginia	4,118.6	4,170.5	4,170.0	4,158.9	162.3	284.1	297.8	298.9	3.9	6.8	7.1	7.2
Washington	3,463.0	3,539.9	3,561.0	3,565.2	181.5	317.8	325.4	330.8	5.2	9.0	9.1	9.3
Seattle-Bellevue-Everett [1]	1,458.6	1,497.0	1,492.2	1,497.1	65.6	116.7	121.3	131.6	4.5	7.8	8.1	8.8
West Virginia	806.4	795.0	793.4	791.5	34.7	61.0	67.0	72.8	4.3	7.7	8.4	9.2
Wisconsin	3,074.1	3,110.8	3,105.4	3,092.5	134.9	268.6	276.4	278.3	4.4	8.6	8.9	9.0
Wyoming	292.6	290.8	291.6	290.9	9.3	13.2	14.7	17.2	3.2	4.5	5.0	5.9
Puerto Rico	1,361.8	1,340.5	1,332.2	1,312.6	152.3	206.4	191.5	190.2	11.2	15.4	14.4	14.5

[1] Metropolitan division.
[2] Metropolitan statistical area.
p = preliminary.
NOTE: Data refer to place of residence. Data for Puerto Rico are derived from a monthly household survey similar to the Current Population Survey. Area definitions are based on Office of Management and Budget Bulletin No. 09-01, dated November 20, 2008, and are available on the BLS Web site at http://www.bls.gov/lau/lausmsa.htm. Estimates for the latest month are subject to revision the following month.

LABOR FORCE DATA
NOT SEASONALLY ADJUSTED

Table 4. Civilian labor force and unemployment by state and selected area, not seasonally adjusted

(Numbers in thousands)

State and area	Civilian labor force				Unemployed							
					Number				Percent of labor force			
	May		June		May		June		May		June	
	2008	2009	2008	2009p	2008	2009	2008	2009p	2008	2009	2008	2009p
Alabama	2,160.4	2,118.2	2,183.6	2,148.4	92.7	197.1	115.2	227.7	4.3	9.3	5.3	10.6
Alaska	357.0	358.9	363.8	367.0	22.8	28.9	24.2	31.1	6.4	8.0	6.6	8.5
Arizona	3,108.4	3,140.0	3,141.3	3,158.3	151.9	250.1	177.0	282.1	4.9	8.0	5.6	8.9
Arkansas	1,378.2	1,364.4	1,391.5	1,390.3	65.1	93.5	72.3	104.6	4.7	6.9	5.2	7.5
California	18,305.3	18,457.7	18,397.4	18,530.8	1,185.9	2,082.0	1,283.1	2,152.0	6.5	11.3	7.0	11.6
Los Angeles-Long Beach-Glendale [1]	4,944.8	4,966.9	4,942.7	4,976.1	333.9	562.0	360.9	564.9	6.8	11.3	7.3	11.4
Colorado	2,714.9	2,702.5	2,751.9	2,723.9	121.8	200.6	137.5	212.5	4.5	7.4	5.0	7.8
Connecticut	1,872.2	1,885.1	1,897.0	1,904.6	99.2	148.9	107.9	154.8	5.3	7.9	5.7	8.1
Delaware	441.8	435.8	446.1	441.3	17.5	33.8	21.0	38.3	4.0	7.8	4.7	8.7
District of Columbia	331.4	326.8	335.4	332.7	21.3	35.0	22.9	37.7	6.4	10.7	6.8	11.3
Florida	9,221.9	9,235.3	9,255.5	9,242.5	508.9	930.0	563.8	996.1	5.5	10.1	6.1	10.8
Miami-Miami Beach-Kendall [1]	1,212.4	1,221.0	1,210.3	1,230.9	63.9	118.0	70.0	141.8	5.3	9.7	5.8	11.5
Georgia	4,851.7	4,758.7	4,860.0	4,786.3	274.5	448.3	303.4	503.2	5.7	9.4	6.2	10.5
Hawaii	654.2	648.0	658.9	650.8	22.5	47.0	29.2	52.6	3.4	7.2	4.4	8.1
Idaho	752.9	748.6	764.0	758.8	29.6	54.3	33.2	60.5	3.9	7.3	4.4	8.0
Illinois	6,716.7	6,645.1	6,804.2	6,746.0	414.0	656.2	470.9	710.9	6.2	9.9	6.9	10.5
Chicago-Naperville-Joliet [1]	4,147.8	4,127.4	4,200.7	4,199.3	257.2	439.7	289.2	474.2	6.2	10.7	6.9	11.3
Indiana	3,243.5	3,227.3	3,275.2	3,258.3	167.0	336.7	185.1	345.4	5.1	10.4	5.7	10.6
Iowa	1,675.3	1,673.0	1,690.8	1,697.3	62.1	89.8	67.9	103.9	3.7	5.4	4.0	6.1
Kansas	1,492.0	1,522.8	1,518.3	1,542.5	61.8	105.1	66.6	108.6	4.1	6.9	4.4	7.0
Kentucky	2,049.4	2,081.0	2,079.9	2,113.3	126.1	219.5	136.1	234.6	6.2	10.5	6.5	11.1
Louisiana	2,066.3	2,066.0	2,105.3	2,105.8	76.5	130.1	106.3	163.5	3.7	6.3	5.1	7.8
Maine	704.3	699.0	717.7	712.2	34.8	56.7	35.3	58.7	4.9	8.1	4.9	8.2
Maryland	3,007.9	2,949.7	3,031.8	2,989.9	117.5	208.5	132.2	224.4	3.9	7.1	4.4	7.5
Massachusetts	3,412.1	3,413.2	3,473.4	3,467.8	162.3	273.5	180.5	302.2	4.8	8.0	5.2	8.7
Michigan	4,967.2	4,847.9	5,017.6	4,944.2	397.5	671.7	422.1	761.4	8.0	13.9	8.4	15.4
Detroit-Warren-Livonia [2]	2,113.2	2,088.4	2,139.8	2,123.3	174.9	310.6	192.3	364.0	8.3	14.9	9.0	17.1
Minnesota	2,929.5	2,951.9	2,958.3	2,987.5	144.5	229.1	156.6	252.2	4.9	7.8	5.3	8.4
Mississippi	1,320.7	1,311.5	1,333.5	1,313.1	91.2	127.5	102.8	129.0	6.9	9.7	7.7	9.8
Missouri	3,022.5	3,015.0	3,067.7	3,052.8	166.8	263.7	186.7	290.3	5.5	8.7	6.1	9.5
Montana	507.2	500.5	512.9	506.8	19.5	29.0	22.7	32.2	3.8	5.8	4.4	6.4
Nebraska	1,001.1	989.7	1,008.5	997.1	31.0	46.7	34.2	51.0	3.1	4.7	3.4	5.1
Nevada	1,363.6	1,402.0	1,372.5	1,404.7	78.8	154.2	87.3	169.8	5.8	11.0	6.4	12.1
New Hampshire	736.7	737.9	746.6	744.9	26.4	47.1	27.9	50.4	3.6	6.4	3.7	6.8
New Jersey	4,481.9	4,547.3	4,536.8	4,599.4	223.0	393.2	234.8	424.4	5.0	8.6	5.2	9.2
New Mexico	955.3	954.5	967.6	962.8	37.1	61.8	44.6	70.6	3.9	6.5	4.6	7.3
New York	9,619.0	9,713.9	9,755.7	9,858.9	471.9	771.6	498.0	846.0	4.9	7.9	5.1	8.6
New York City	3,913.7	3,997.5	3,937.2	4,023.9	187.7	346.3	202.2	375.9	4.8	8.7	5.1	9.3
North Carolina	4,544.7	4,564.0	4,572.5	4,598.3	261.3	503.7	282.1	514.9	5.7	11.0	6.2	11.2
North Dakota	372.1	370.1	381.0	376.1	10.4	14.9	13.3	17.2	2.8	4.0	3.5	4.6
Ohio	5,982.9	5,967.9	6,048.7	6,031.6	356.6	623.4	398.7	674.0	6.0	10.4	6.6	11.2
Cleveland-Elyria-Mentor [2]	1,090.1	1,077.3	1,102.1	1,091.6	70.5	108.4	76.2	110.2	6.5	10.1	6.9	10.1
Oklahoma	1,746.7	1,771.5	1,772.3	1,803.0	62.4	112.6	71.2	118.0	3.6	6.4	4.0	6.5
Oregon	1,942.6	1,987.5	1,965.0	1,996.0	103.4	236.2	113.7	241.2	5.3	11.9	5.8	12.1
Pennsylvania	6,380.4	6,454.9	6,450.7	6,496.0	316.4	526.0	341.0	547.3	5.0	8.1	5.3	8.4
Rhode Island	563.8	561.2	570.8	572.4	41.1	67.7	43.0	69.9	7.3	12.1	7.5	12.2
South Carolina	2,158.8	2,209.7	2,184.4	2,230.9	126.7	255.2	143.9	273.6	5.9	11.5	6.6	12.3
South Dakota	447.4	448.4	453.5	456.0	12.4	21.9	12.5	22.4	2.8	4.9	2.8	4.9
Tennessee	3,038.0	3,024.3	3,078.6	3,075.9	179.9	311.4	205.2	341.0	5.9	10.3	6.7	11.1
Texas	11,639.2	11,920.0	11,762.6	12,075.2	519.1	821.7	600.3	965.0	4.5	6.9	5.1	8.0
Utah	1,378.6	1,377.7	1,389.9	1,379.4	42.6	72.3	49.0	81.7	3.1	5.3	3.5	5.9
Vermont	352.5	357.9	359.0	363.2	15.1	25.5	16.0	25.5	4.3	7.1	4.5	7.0
Virginia	4,139.1	4,175.2	4,163.1	4,197.2	150.6	292.9	166.6	308.1	3.6	7.0	4.0	7.3
Washington	3,445.9	3,544.7	3,475.5	3,580.6	168.5	317.0	177.9	330.0	4.9	8.9	5.1	9.2
Seattle-Bellevue-Everett [1]	1,459.7	1,498.2	1,460.5	1,504.9	61.9	122.3	63.2	137.5	4.2	8.2	4.3	9.1
West Virginia	813.2	794.6	823.0	806.6	33.9	66.2	36.6	75.9	4.2	8.3	4.4	9.4
Wisconsin	3,067.3	3,087.5	3,133.5	3,145.4	127.5	268.8	146.6	289.2	4.2	8.7	4.7	9.2
Wyoming	290.7	289.8	298.0	296.1	8.5	14.5	8.8	17.0	2.9	5.0	3.0	5.7
Puerto Rico	1,375.0	1,334.6	1,375.3	1,316.7	156.1	191.3	162.9	199.5	11.4	14.3	11.8	15.2

[1] Metropolitan division.
[2] Metropolitan statistical area.
p = preliminary.

NOTE: Data refer to place of residence. Data for Puerto Rico are derived from a monthly household survey similar to the Current Population Survey. Area definitions are based on Office of Management and Budget Bulletin No. 09-01, dated November 20, 2008, and are available on the BLS Web site at http://www.bls.gov/lau/lausmsa.htm. Estimates for the latest month are subject to revision the following month.

ESTABLISHMENT DATA
SEASONALLY ADJUSTED

Table 5. Employees on nonfarm payrolls by state and selected industry sector, seasonally adjusted

(In thousands)

State	Total[1]				Construction				Manufacturing			
	June 2008	Apr. 2009	May 2009	June 2009[p]	June 2008	Apr. 2009	May 2009	June 2009[p]	June 2008	Apr. 2009	May 2009	June 2009[p]
Alabama	1,999.5	1,912.9	1,911.3	1,909.8	110.1	92.0	91.0	91.4	(2)	(2)	(2)	(2)
Alaska	322.3	320.9	322.5	322.3	17.3	16.6	16.1	16.2	13.1	12.5	13.4	13.0
Arizona	2,627.6	2,462.3	2,438.4	2,434.1	189.0	141.7	139.4	140.8	174.1	166.5	165.0	162.7
Arkansas	1,203.5	1,179.2	1,173.7	1,177.1	55.9	53.2	52.1	54.3	183.0	167.0	163.6	162.9
California	15,051.3	14,412.3	14,351.5	14,285.0	789.1	665.4	655.3	642.0	1,430.6	1,324.0	1,314.1	1,306.0
Colorado	2,353.4	2,266.7	2,261.8	2,249.3	163.1	140.6	138.8	138.0	145.2	133.4	131.8	129.9
Connecticut	1,704.3	1,640.3	1,644.0	1,639.2	65.5	51.9	53.0	51.3	188.0	175.1	174.2	173.5
Delaware [3]	434.0	415.7	414.9	412.4	25.6	22.5	22.1	21.5	(2)	(2)	(2)	(2)
District of Columbia [3]	704.9	702.4	703.4	703.0	12.8	12.3	12.2	12.1	(2)	(2)	(2)	(2)
Florida	7,772.2	7,450.1	7,399.3	7,379.4	515.2	427.4	435.2	434.8	373.5	340.0	335.0	331.2
Georgia	4,118.8	3,933.5	3,918.7	3,904.5	206.5	176.4	171.6	168.8	410.5	364.8	361.5	360.4
Hawaii [3]	619.5	604.5	602.0	599.9	37.9	32.7	32.8	32.8	(2)	(2)	(2)	(2)
Idaho	650.4	618.6	616.4	618.4	45.4	40.1	39.7	39.1	63.5	57.4	57.0	56.0
Illinois	5,958.7	5,717.8	5,700.0	5,686.1	258.7	228.1	226.0	220.6	661.3	593.5	583.8	581.0
Indiana	2,968.1	2,836.0	2,818.7	2,815.1	145.1	125.3	127.1	127.1	527.6	453.8	437.9	429.4
Iowa	1,523.0	1,487.8	1,483.4	1,480.0	73.1	66.5	66.9	65.8	228.2	206.9	202.3	200.5
Kansas	1,387.1	1,360.5	1,355.9	1,336.5	65.1	57.0	56.6	56.2	188.6	173.6	170.8	169.2
Kentucky	1,856.5	1,790.3	1,780.0	1,774.2	85.3	70.9	69.1	68.8	246.7	211.6	210.1	207.0
Louisiana	1,940.2	1,932.3	1,930.6	1,928.8	135.2	139.5	140.1	140.6	152.6	146.5	144.6	143.7
Maine	617.7	598.9	598.0	598.3	29.4	26.2	26.1	25.8	59.4	54.0	53.2	53.5
Maryland [3]	2,601.2	2,543.2	2,546.1	2,545.0	180.2	154.7	154.3	154.3	128.7	124.0	123.5	123.0
Massachusetts	3,293.8	3,184.1	3,189.7	3,187.4	132.9	116.6	113.8	111.6	287.3	273.0	273.0	271.1
Michigan	4,183.4	3,901.5	3,877.1	3,845.8	153.5	133.5	130.7	125.3	588.7	471.1	455.3	436.1
Minnesota	2,764.5	2,669.1	2,665.8	2,649.1	111.1	95.1	97.0	93.1	335.9	304.0	300.2	296.5
Mississippi	1,151.9	1,118.4	1,116.4	1,120.9	62.4	58.7	60.4	61.9	161.2	145.4	143.2	144.7
Missouri	2,797.0	2,727.8	2,725.1	2,717.8	140.7	129.7	127.5	127.4	292.1	262.6	259.9	257.4
Montana	445.5	439.9	438.0	440.7	29.6	25.7	24.9	25.9	20.1	19.3	19.3	19.2
Nebraska [3]	963.6	946.3	947.0	948.5	50.1	47.4	48.2	48.7	101.6	94.2	93.9	92.9
Nevada	1,271.5	1,201.6	1,198.4	1,192.4	118.4	97.1	93.2	91.7	48.5	45.0	45.0	45.1
New Hampshire	646.3	631.5	632.8	633.0	25.7	21.7	21.4	21.3	76.5	69.2	69.1	68.4
New Jersey	4,066.2	3,941.3	3,933.3	3,931.2	164.8	146.8	141.3	140.7	301.3	271.4	271.4	272.0
New Mexico	847.4	825.2	826.2	819.0	57.6	49.2	49.4	48.7	35.4	32.1	31.7	31.6
New York	8,802.9	8,627.5	8,605.2	8,582.2	360.6	338.0	336.1	334.8	536.0	500.5	495.2	491.7
North Carolina	4,138.7	3,949.5	3,942.3	3,947.0	237.2	195.8	195.6	193.9	517.2	453.9	449.1	443.6
North Dakota	366.8	368.4	370.9	372.8	21.0	19.6	21.1	22.1	26.5	24.9	24.4	23.7
Ohio	5,379.2	5,132.9	5,133.2	5,100.2	211.5	181.8	183.7	181.2	744.6	638.2	626.0	610.6
Oklahoma	1,590.3	1,569.1	1,559.6	1,559.8	75.2	74.7	72.9	72.4	151.2	138.5	135.6	135.6
Oregon	1,723.5	1,636.0	1,634.4	1,627.2	95.4	78.9	78.9	80.5	196.1	170.8	169.3	167.4
Pennsylvania	5,806.9	5,648.3	5,634.1	5,630.7	256.8	234.8	234.5	235.4	647.1	581.6	577.4	573.7
Rhode Island	482.7	464.6	463.8	462.9	20.5	17.8	18.1	17.9	48.3	43.7	43.4	43.1
South Carolina	1,942.1	1,851.4	1,851.3	1,851.1	113.1	103.8	104.3	102.4	243.3	218.5	215.5	213.5
South Dakota [3]	410.5	404.0	404.3	404.3	23.3	22.1	22.5	22.2	42.8	39.2	38.8	38.0
Tennessee [3]	2,779.1	2,666.1	2,662.2	2,649.9	132.7	111.8	108.5	106.4	365.6	325.8	319.3	314.2
Texas	10,625.0	10,426.6	10,399.3	10,358.7	672.5	615.6	604.6	594.4	925.4	867.6	855.5	845.2
Utah	1,254.6	1,219.0	1,214.7	1,207.9	90.9	76.6	75.0	74.2	126.3	114.3	113.6	113.2
Vermont	306.3	295.4	295.2	294.0	15.7	13.2	13.4	13.7	35.0	31.1	30.8	30.3
Virginia	3,761.1	3,672.7	3,677.6	3,654.8	223.1	194.6	192.4	190.5	265.8	243.9	241.0	237.6
Washington	2,963.4	2,869.4	2,865.2	2,858.1	202.8	178.3	176.7	174.6	294.0	269.4	266.9	267.8
West Virginia	758.4	738.8	738.7	736.3	37.9	34.4	35.3	35.0	56.6	51.7	50.8	50.5
Wisconsin	2,871.9	2,752.3	2,754.7	2,753.5	118.1	101.6	106.7	104.1	494.6	441.8	438.7	441.9
Wyoming	297.5	293.2	291.4	289.5	27.9	25.4	25.1	24.1	10.0	9.7	9.9	9.9

See footnotes at end of table.

ESTABLISHMENT DATA
SEASONALLY ADJUSTED

Table 5. Employees on nonfarm payrolls by state and selected industry sector, seasonally adjusted—Continued

(In thousands)

State	Trade, transportation, and utilities				Financial activities				Professional and business services			
	June 2008	Apr. 2009	May 2009	June 2009p	June 2008	Apr. 2009	May 2009	June 2009p	June 2008	Apr. 2009	May 2009	June 2009p
Alabama	390.4	377.9	377.7	376.1	99.2	99.8	97.8	98.0	220.8	201.5	202.6	202.0
Alaska	64.7	63.7	62.7	63.3	14.8	14.6	14.9	14.6	25.9	26.4	26.5	25.9
Arizona	522.6	482.7	482.1	480.0	176.4	169.2	167.4	167.6	385.5	352.9	342.1	337.1
Arkansas	248.3	236.0	236.8	236.9	52.3	49.8	50.1	49.3	116.9	115.9	115.1	110.6
California	2,874.4	2,700.2	2,695.3	2,683.9	851.7	807.3	804.4	802.6	2,248.2	2,141.8	2,131.4	2,117.7
Colorado	431.7	414.5	414.6	415.0	156.1	147.4	147.8	146.4	352.0	323.4	324.6	320.9
Connecticut	311.0	297.6	298.8	298.7	143.9	140.0	139.9	139.5	206.1	191.8	191.2	189.4
Delaware [3]	81.4	76.3	76.9	76.5	45.9	44.8	44.6	44.3	59.5	53.8	53.7	53.5
District of Columbia [3]	28.1	26.5	26.6	26.3	28.4	27.5	27.6	27.0	152.9	150.3	149.8	148.0
Florida	1,588.2	1,519.6	1,513.3	1,501.9	525.1	507.6	504.9	502.5	1,151.1	1,076.1	1,064.7	1,062.6
Georgia	877.7	835.8	831.4	828.3	225.4	215.8	214.3	212.7	565.1	516.3	508.6	512.1
Hawaii [3]	118.3	113.7	113.6	112.9	29.4	28.8	28.7	28.5	75.2	73.2	73.8	72.9
Idaho	131.8	122.4	122.0	121.8	31.7	31.0	30.7	30.7	80.6	74.3	74.0	75.8
Illinois	1,206.6	1,165.8	1,160.9	1,155.8	393.3	377.1	375.7	375.2	864.7	796.8	796.0	798.4
Indiana	582.4	559.8	559.8	559.7	136.0	133.3	131.9	133.4	285.5	266.0	263.9	265.6
Iowa	309.1	312.7	312.6	313.0	102.8	102.0	102.7	103.2	122.8	112.6	113.3	111.7
Kansas	263.2	259.0	257.1	255.4	73.4	71.6	71.3	71.2	148.8	140.0	139.8	137.1
Kentucky	382.6	373.7	368.6	366.9	91.7	89.9	88.4	89.1	184.3	177.9	173.7	172.8
Louisiana	383.8	379.4	378.3	378.8	95.5	92.3	92.4	91.4	205.3	201.7	201.5	201.8
Maine	125.0	120.4	120.0	119.2	32.8	32.0	31.9	32.0	56.1	54.7	55.4	56.0
Maryland [3]	467.6	449.7	448.2	448.2	153.3	145.3	143.4	143.0	398.4	394.4	396.8	396.7
Massachusetts	570.7	546.9	547.3	546.2	221.4	209.5	209.7	208.6	488.0	455.8	458.1	456.8
Michigan	773.6	724.8	719.6	718.6	204.9	193.2	192.4	192.1	562.0	504.5	502.3	492.8
Minnesota	523.3	508.1	503.1	503.9	176.8	174.4	174.6	175.2	328.5	295.4	294.8	291.3
Mississippi	223.9	217.2	216.5	218.1	([2])	([2])	([2])	([2])	95.5	88.5	86.9	85.9
Missouri	544.1	530.7	529.6	530.0	165.5	162.1	162.9	162.3	342.6	333.1	332.6	328.5
Montana	92.2	89.5	88.5	88.1	21.9	21.8	21.7	21.6	40.6	39.1	39.2	39.3
Nebraska [3]	204.9	201.0	199.6	200.1	69.1	68.4	68.7	68.5	105.6	99.7	99.0	98.6
Nevada	232.2	224.4	225.7	226.0	61.7	59.0	58.8	58.4	153.7	141.6	141.4	139.7
New Hampshire	140.1	139.4	139.7	139.8	38.2	37.4	37.0	37.3	66.6	64.4	65.0	65.3
New Jersey	866.8	847.7	843.9	844.8	271.4	259.0	258.2	256.8	616.4	577.8	578.3	576.0
New Mexico	145.2	138.8	138.7	136.8	34.8	33.8	33.7	32.7	108.0	105.4	105.0	104.8
New York	1,528.5	1,473.1	1,466.9	1,466.3	725.0	693.8	690.4	685.1	1,159.1	1,122.0	1,118.5	1,107.5
North Carolina	772.3	729.7	730.6	733.6	212.2	203.7	202.7	199.8	506.9	466.0	465.1	465.8
North Dakota	77.6	78.7	79.0	79.6	20.3	20.3	20.0	20.3	30.3	29.8	29.7	30.0
Ohio	1,039.6	998.3	1,000.7	999.9	290.6	277.5	278.8	279.9	670.5	617.6	618.6	613.0
Oklahoma	289.0	286.5	286.3	285.3	83.2	80.5	80.2	80.3	184.1	175.3	171.4	168.8
Oregon	337.2	313.4	313.8	311.5	102.1	96.3	95.6	94.8	196.3	180.4	180.4	179.1
Pennsylvania	1,129.7	1,096.6	1,096.1	1,092.2	330.5	318.1	316.3	317.3	710.7	680.0	673.9	669.5
Rhode Island	77.7	73.7	73.3	73.4	33.4	32.2	32.3	32.4	54.8	52.1	51.9	52.0
South Carolina	374.5	358.4	358.2	356.0	106.3	102.5	103.7	102.9	224.3	211.5	210.5	213.0
South Dakota [3]	81.9	81.6	81.4	81.7	31.3	30.1	29.8	30.0	28.0	26.7	26.2	26.5
Tennessee [3]	604.1	577.8	574.2	573.9	145.1	137.8	138.6	137.5	326.0	305.1	307.8	303.7
Texas	2,149.1	2,085.1	2,076.0	2,054.3	648.5	640.5	641.9	642.9	1,341.8	1,276.9	1,275.8	1,263.9
Utah	249.5	243.1	242.9	241.6	74.2	73.0	72.1	71.2	162.8	157.4	155.9	154.6
Vermont	59.3	56.5	57.1	56.6	12.8	12.6	12.7	12.6	22.9	20.8	21.1	20.9
Virginia	661.6	640.9	643.6	641.9	188.2	187.3	185.7	186.6	657.2	641.6	642.9	634.1
Washington	553.9	529.6	531.3	529.3	152.8	147.4	146.6	147.0	351.0	329.8	327.5	327.4
West Virginia	142.1	136.5	136.2	136.1	29.7	28.3	28.3	28.2	60.7	58.5	58.5	58.3
Wisconsin	541.8	516.7	512.6	512.4	164.2	159.9	159.6	158.8	279.7	255.0	256.9	254.1
Wyoming	55.7	55.7	55.5	55.2	11.6	11.6	11.6	11.5	18.6	17.8	17.8	17.6

See footnotes at end of table.

ESTABLISHMENT DATA
SEASONALLY ADJUSTED

Table 5. Employees on nonfarm payrolls by state and selected industry sector, seasonally adjusted—Continued

(In thousands)

State	Education and health services				Leisure and hospitality				Government			
	June 2008	Apr. 2009	May 2009	June 2009p	June 2008	Apr. 2009	May 2009	June 2009p	June 2008	Apr. 2009	May 2009	June 2009p
Alabama	211.2	213.6	217.2	216.5	174.8	172.8	173.2	174.4	384.8	383.6	383.1	385.0
Alaska	37.2	38.3	38.6	38.4	32.6	31.7	32.5	32.0	83.1	83.6	83.9	84.5
Arizona	319.9	315.9	314.8	317.0	269.7	257.6	258.1	260.0	433.9	431.6	426.6	425.4
Arkansas	157.3	162.5	164.3	168.9	100.6	103.4	101.5	101.2	214.4	218.1	217.9	220.1
California	1,723.9	1,744.8	1,744.3	1,743.4	1,576.6	1,518.3	1,516.2	1,512.2	2,528.0	2,523.8	2,512.2	2,505.5
Colorado	249.1	256.0	257.5	258.3	274.6	266.2	262.7	262.2	382.0	391.4	393.2	389.8
Connecticut	296.3	299.8	300.7	300.2	138.4	135.7	137.8	137.5	252.6	248.9	250.0	249.4
Delaware [3]	60.1	61.5	61.3	61.3	40.0	39.5	39.7	40.0	61.9	62.1	61.6	61.4
District of Columbia [3]	102.8	106.7	106.4	108.2	57.7	57.9	58.5	58.7	234.6	236.0	236.7	236.1
Florida	1,042.4	1,059.2	1,050.7	1,048.2	947.6	913.0	897.3	899.1	1,122.9	1,120.0	1,115.3	1,117.7
Georgia	463.7	477.4	480.5	473.7	395.2	385.2	388.7	384.8	694.2	692.1	694.5	696.3
Hawaii [3]	73.9	74.4	74.7	75.0	107.5	102.0	101.3	101.2	124.5	129.8	126.6	126.5
Idaho	78.2	78.1	78.7	79.1	63.6	59.7	59.9	59.8	118.9	121.0	120.5	120.8
Illinois	798.7	802.4	803.9	805.4	533.2	513.5	517.6	518.0	853.2	861.3	858.2	852.4
Indiana	407.0	418.0	416.9	416.3	283.8	286.5	288.7	289.1	442.5	440.0	439.3	439.4
Iowa	205.9	210.1	209.6	210.3	135.4	132.3	132.0	132.7	252.5	253.5	253.2	252.9
Kansas	176.4	178.1	178.2	176.9	116.2	115.1	115.1	114.3	253.6	264.2	265.1	254.7
Kentucky	244.2	246.1	246.9	248.1	171.3	173.8	173.3	173.4	322.3	318.9	321.0	320.8
Louisiana	255.6	258.5	259.8	258.4	195.0	196.9	196.9	196.6	362.5	366.9	367.7	367.2
Maine	117.7	118.7	119.1	119.5	60.0	57.3	57.4	58.0	104.0	103.4	102.8	102.7
Maryland [3]	381.8	389.4	390.7	390.3	237.2	228.4	233.4	236.2	486.1	493.2	492.1	491.5
Massachusetts	639.3	645.6	648.1	652.8	306.3	296.8	300.9	304.0	435.8	438.0	434.3	432.0
Michigan	607.8	612.8	611.6	612.8	398.0	383.9	386.3	387.1	649.9	641.8	643.2	648.4
Minnesota	441.2	459.3	458.9	458.2	245.7	235.7	240.9	237.9	419.8	419.3	420.4	419.6
Mississippi	128.4	129.1	129.7	129.9	125.4	123.1	123.2	122.6	247.6	252.5	252.5	253.1
Missouri	392.5	398.0	399.2	399.4	281.7	276.2	277.1	276.3	447.3	450.6	451.6	451.6
Montana	60.6	63.2	61.8	63.2	59.2	58.6	59.1	58.6	87.9	90.0	91.0	91.7
Nebraska [3]	132.2	134.3	134.7	135.2	82.4	81.0	82.3	83.8	163.7	167.8	167.8	167.7
Nevada	95.8	97.3	98.0	98.3	335.4	316.3	315.0	313.1	161.5	157.4	157.4	156.8
New Hampshire	104.9	107.1	106.9	106.7	63.5	63.0	62.4	61.8	95.0	94.8	95.6	98.5
New Jersey	590.2	599.2	597.7	598.9	343.9	332.8	336.6	334.0	651.3	652.1	651.3	650.7
New Mexico	114.9	117.1	118.4	119.0	86.3	84.6	85.1	82.7	197.3	200.3	199.8	199.3
New York	1,629.3	1,659.3	1,657.4	1,660.9	715.9	706.6	705.3	705.8	1,510.8	1,505.1	1,509.2	1,503.9
North Carolina	534.6	543.9	543.5	542.4	397.8	388.4	392.2	390.1	705.1	720.0	715.2	729.1
North Dakota	51.7	52.5	52.9	53.5	33.4	33.4	34.5	35.2	76.4	79.2	79.5	78.7
Ohio	814.7	822.6	828.6	828.5	493.6	499.0	498.1	495.2	796.6	790.0	790.3	784.3
Oklahoma	198.2	199.0	200.1	200.1	143.6	145.5	145.9	147.6	321.8	331.7	331.3	334.7
Oregon	219.8	224.5	224.9	226.0	173.9	166.8	167.7	167.9	296.6	302.2	301.7	298.0
Pennsylvania	1,098.1	1,118.7	1,117.1	1,124.5	503.1	491.3	493.1	493.6	748.2	752.8	753.1	753.7
Rhode Island	99.8	99.8	99.7	99.9	50.9	50.0	50.7	50.2	63.6	62.6	62.1	61.5
South Carolina	207.1	206.6	208.2	209.5	220.3	204.0	204.7	204.0	348.7	341.1	341.5	344.0
South Dakota [3]	62.0	63.1	63.4	63.9	43.1	42.1	42.7	42.6	75.3	76.5	76.9	76.6
Tennessee [3]	357.7	364.9	363.8	366.3	273.5	268.1	271.0	271.9	419.2	426.1	430.3	429.0
Texas	1,285.9	1,338.6	1,343.2	1,343.2	1,011.9	1,016.0	1,017.3	1,018.2	1,782.0	1,809.1	1,811.7	1,831.0
Utah	145.8	149.7	150.1	148.8	114.8	110.9	110.8	111.0	211.2	217.1	217.7	217.1
Vermont	58.4	60.2	60.2	60.3	32.5	31.2	30.3	30.0	53.6	53.9	54.2	53.9
Virginia	436.8	441.0	440.3	447.1	349.8	343.8	350.1	346.1	691.2	700.5	704.8	695.5
Washington	360.4	364.2	364.6	363.5	285.0	283.7	286.8	288.9	543.6	551.9	550.3	545.1
West Virginia	116.8	117.7	117.9	118.6	72.0	70.5	71.3	70.9	144.9	146.9	147.0	146.1
Wisconsin	404.3	414.4	413.0	412.9	259.1	248.7	252.2	257.8	417.6	428.6	428.5	427.1
Wyoming	([2])	([2])	([2])	([2])	34.5	33.6	33.5	33.3	69.3	70.4	70.9	70.8

[1] Includes mining and logging, information, and other services (except public administration), not shown separately.

[2] This series is not published seasonally adjusted because the seasonal component, which is small relative to the trend-cycle and irregular components, cannot be separated with sufficient precision.

[3] Mining and logging is combined with construction.

p = preliminary.

NOTE: Data are counts of jobs by place of work. Estimates are currently projected from 2008 benchmark levels. Estimates subsequent to the current benchmarks are provisional and will be revised when new information becomes available.

ESTABLISHMENT DATA
NOT SEASONALLY ADJUSTED

Table 6. Employees on nonfarm payrolls by state and selected industry sector, not seasonally adjusted

(In thousands)

State	Total				Mining and Logging				Construction				Manufacturing			
	May		June		May		June		May		June		May		June	
	2008	2009	2008	2009p	2008	2009	2008	2009p	2008	2009	2008	2009p	2008	2009	2008	2009p
Alabama	2,012.0	1,917.0	2,011.2	1,917.6	12.5	12.6	12.6	12.5	111.0	91.5	110.8	92.1	287.7	253.3	287.7	251.9
Alaska	328.9	326.4	340.9	339.8	15.1	15.4	15.5	15.8	17.8	16.5	19.9	18.7	10.9	10.9	15.8	15.7
Arizona	2,648.3	2,454.9	2,602.8	2,405.5	13.3	10.6	13.7	10.9	193.4	139.2	192.0	141.6	174.7	164.9	174.6	162.8
Arkansas	1,213.2	1,180.9	1,208.6	1,182.0	10.6	11.6	10.8	11.8	56.7	52.8	57.4	55.9	183.8	163.7	183.9	163.8
California	15,126.4	14,395.5	15,149.7	14,367.5	28.6	27.2	29.0	27.4	803.4	651.1	805.4	653.4	1,434.1	1,312.2	1,438.8	1,309.9
Colorado	2,359.8	2,262.4	2,379.1	2,274.7	28.0	26.2	28.5	25.3	165.0	139.2	169.7	144.2	145.5	131.5	145.9	130.5
Connecticut	1,717.3	1,653.4	1,724.7	1,658.3	.8	.7	.8	.7	67.5	54.1	68.3	54.3	188.5	174.2	189.7	174.7
Delaware	437.0	417.4	440.9	418.8	([1])	([1])	([1])	([1])	26.2	22.2	26.3	22.2	31.4	27.6	32.4	27.2
District of Columbia	703.3	702.8	704.5	703.2	([1])	([1])	([1])	([1])	12.9	12.3	13.0	12.3	1.7	1.3	1.7	1.3
Florida	7,848.6	7,430.9	7,711.2	7,306.0	6.3	6.2	6.3	6.2	524.2	434.8	522.4	437.6	377.2	334.6	375.7	332.3
Georgia	4,147.4	3,931.4	4,119.3	3,909.8	10.3	9.8	10.2	9.8	209.4	172.6	208.1	171.7	413.5	362.8	412.2	362.2
Hawaii	625.4	605.1	623.4	602.5	([1])	([1])	([1])	([1])	38.0	32.8	38.1	33.0	15.1	14.3	15.0	14.3
Idaho	655.8	619.2	661.4	628.7	4.0	2.6	4.5	3.7	46.9	39.8	48.3	41.6	63.9	56.5	64.2	56.3
Illinois	6,012.3	5,730.7	6,023.0	5,744.1	10.2	10.4	10.2	10.5	267.4	231.7	273.8	235.1	663.3	583.6	666.1	584.5
Indiana	3,002.5	2,842.8	2,978.7	2,817.3	6.8	7.0	6.9	7.0	148.7	129.9	151.9	134.1	533.4	438.8	533.7	434.7
Iowa	1,545.3	1,500.3	1,543.7	1,499.5	2.3	2.3	2.3	2.3	75.9	68.9	78.4	71.3	229.5	203.0	230.4	202.5
Kansas	1,405.6	1,364.9	1,404.5	1,351.4	9.6	10.1	9.6	10.1	66.2	56.8	68.2	59.2	185.5	170.8	189.3	170.0
Kentucky	1,878.7	1,789.7	1,872.3	1,786.2	23.4	25.7	23.7	25.8	87.6	70.2	88.2	71.6	250.9	210.2	248.0	208.6
Louisiana	1,949.3	1,934.0	1,947.0	1,932.2	54.4	52.3	55.0	52.6	135.5	140.4	136.9	141.1	153.4	144.8	153.6	144.5
Maine	622.4	600.3	632.4	611.6	1.8	1.6	2.3	2.0	30.6	26.9	31.5	28.1	59.3	53.3	60.1	54.0
Maryland	2,626.4	2,561.8	2,629.5	2,572.3	([1])	([1])	([1])	([1])	182.3	154.8	184.1	157.9	128.9	123.1	129.4	123.6
Massachusetts	3,320.4	3,208.1	3,336.7	3,228.6	1.5	1.3	1.5	1.3	136.8	116.0	140.0	118.4	288.2	273.0	289.7	273.0
Michigan	4,227.0	3,927.2	4,242.3	3,903.1	8.0	7.6	8.2	7.8	160.6	136.0	166.3	138.4	577.5	457.0	596.9	441.7
Minnesota	2,791.9	2,693.9	2,814.5	2,702.2	6.3	5.0	6.4	4.4	115.7	100.1	122.6	103.3	336.7	300.3	340.8	301.2
Mississippi	1,160.9	1,120.0	1,152.7	1,120.4	9.5	9.5	9.5	9.5	64.5	60.4	63.9	62.8	162.6	143.5	161.8	145.0
Missouri	2,828.4	2,752.1	2,828.5	2,746.4	4.9	4.9	5.0	4.9	144.4	129.4	146.7	132.8	294.1	260.9	294.7	259.1
Montana	450.8	439.9	454.9	450.2	8.0	8.1	8.3	8.3	30.8	25.1	31.8	27.6	20.3	19.2	20.3	19.4
Nebraska	975.5	955.1	976.3	959.3	([1])	([1])	([1])	([1])	51.9	49.0	53.1	51.2	102.2	93.5	102.1	93.2
Nevada	1,285.6	1,203.1	1,278.9	1,195.2	12.0	12.5	12.3	12.6	120.6	93.4	121.2	92.6	49.0	45.1	49.0	45.3
New Hampshire	650.1	634.9	655.7	642.0	1.0	1.0	1.1	1.0	26.7	21.8	27.3	22.5	76.3	69.0	76.8	68.7
New Jersey	4,093.8	3,952.0	4,140.3	3,993.9	1.7	1.7	1.7	1.7	168.6	143.3	170.7	145.9	302.2	271.1	303.5	273.8
New Mexico	851.8	830.6	849.8	823.4	21.0	19.3	21.3	19.3	58.5	49.9	59.0	50.4	35.3	31.4	35.4	31.7
New York	8,846.4	8,645.6	8,887.4	8,672.5	6.6	6.4	6.9	6.6	366.5	341.6	373.7	349.8	536.8	495.0	540.4	496.5
North Carolina	4,176.3	3,975.0	4,158.3	3,962.9	6.6	6.4	6.6	6.4	241.1	197.4	240.7	196.9	520.5	449.9	519.2	446.4
North Dakota	371.7	374.6	370.9	376.3	6.5	7.5	6.8	7.6	21.3	21.9	23.2	24.6	26.4	24.2	26.9	24.0
Ohio	5,438.1	5,169.5	5,431.8	5,148.7	11.9	11.8	12.0	11.9	218.3	187.4	223.7	192.2	746.2	625.2	750.4	613.9
Oklahoma	1,608.5	1,571.1	1,594.8	1,562.7	51.4	45.3	52.6	46.1	76.1	73.5	77.0	74.5	151.8	135.6	152.0	135.6
Oregon	1,736.0	1,642.2	1,741.0	1,643.0	8.4	7.1	8.7	7.4	96.0	77.8	96.9	81.4	196.1	167.7	196.7	168.7
Pennsylvania	5,862.3	5,677.8	5,856.1	5,675.3	22.1	23.5	22.6	24.2	264.4	239.3	269.3	247.4	649.3	577.3	652.3	578.7
Rhode Island	489.7	467.9	489.8	468.9	.3	.2	.2	.2	21.2	18.4	21.8	19.0	48.6	43.3	48.6	43.3
South Carolina	1,963.5	1,872.5	1,958.1	1,865.4	4.4	4.2	4.3	4.2	114.3	104.7	114.2	103.3	245.7	216.4	244.6	214.8
South Dakota	416.6	410.5	421.0	414.5	([1])	([1])	([1])	([1])	24.5	23.6	25.6	24.6	42.9	38.8	43.2	38.5
Tennessee	2,805.9	2,673.2	2,782.3	2,655.1	([1])	([1])	([1])	([1])	137.5	109.8	136.2	109.6	366.9	319.9	367.0	316.0
Texas	10,663.6	10,438.6	10,666.2	10,391.6	226.3	209.5	230.5	206.5	679.9	606.7	682.8	603.2	928.3	854.1	931.0	848.0
Utah	1,256.7	1,213.7	1,261.6	1,215.1	12.3	13.7	12.6	13.9	92.6	75.6	94.1	76.4	126.7	113.6	126.8	113.6
Vermont	308.6	295.3	308.7	296.8	.9	.8	.9	.9	16.2	13.9	17.1	15.0	35.1	30.8	35.3	30.7
Virginia	3,787.7	3,690.5	3,806.8	3,695.0	11.0	11.1	11.0	11.3	226.2	192.6	227.9	194.5	266.6	241.6	266.8	239.0
Washington	2,981.4	2,875.3	2,993.4	2,888.6	7.5	7.1	7.6	7.3	204.7	177.0	207.0	178.7	293.4	265.4	294.8	268.8
West Virginia	766.8	744.8	763.7	741.0	30.5	27.7	31.0	27.2	39.0	36.4	39.6	36.8	56.8	50.8	57.0	50.8
Wisconsin	2,903.7	2,774.5	2,923.2	2,800.2	3.5	3.3	3.6	3.4	123.4	109.8	127.5	113.0	493.7	436.3	501.8	447.6
Wyoming	298.9	292.9	308.0	300.1	28.6	26.0	29.3	25.8	28.4	25.9	29.3	25.8	9.8	9.7	10.0	9.8
Puerto Rico	1,015.4	977.4	1,029.5	982.1	([1])	([1])	([1])	([1])	58.2	48.0	57.6	46.6	102.0	93.0	101.5	92.1

See footnotes at end of table.

ESTABLISHMENT DATA
NOT SEASONALLY ADJUSTED

Table 6. Employees on nonfarm payrolls by state and selected industry sector, not seasonally adjusted—Continued

(In thousands)

State	Trade, transportation, and utilities				Information				Financial activities				Professional and business services			
	May		June		May		June		May		June		May		June	
	2008	2009	2008	2009p	2008	2009	2008	2009p	2008	2009	2008	2009p	2008	2009	2008	2009p
Alabama	390.2	377.2	390.5	376.2	27.2	25.8	27.0	25.7	99.4	97.7	99.8	98.5	222.0	202.5	221.9	202.9
Alaska	66.9	64.4	69.0	67.5	7.1	7.1	7.0	7.2	15.0	15.0	15.2	15.0	26.9	26.9	27.7	27.8
Arizona	519.1	479.7	517.6	476.2	43.2	39.5	42.8	38.8	177.1	167.1	176.7	167.2	389.8	342.5	386.8	338.3
Arkansas	248.5	236.8	248.9	237.5	18.7	17.0	18.6	17.0	52.7	50.1	52.7	49.7	118.0	115.1	117.5	111.2
California	2,856.7	2,675.7	2,860.6	2,675.8	480.7	448.1	483.6	444.8	857.3	805.1	856.0	804.0	2,246.7	2,128.0	2,253.5	2,123.4
Colorado	427.8	411.2	431.6	415.4	77.1	72.8	77.4	72.9	156.0	147.2	156.7	147.2	354.2	326.9	358.4	328.6
Connecticut	311.0	298.5	313.2	301.3	38.5	35.0	38.5	35.7	143.5	139.7	145.3	140.3	207.5	191.8	210.3	193.5
Delaware	81.3	76.3	82.0	77.0	7.1	7.1	7.2	7.2	45.7	44.4	46.3	44.5	59.8	54.1	59.8	54.0
District of Columbia	27.9	26.6	28.2	26.4	21.0	19.3	20.8	19.4	28.3	27.5	28.4	27.1	153.8	149.9	155.3	150.4
Florida	1,590.8	1,507.1	1,579.3	1,493.7	158.1	147.0	157.6	144.4	528.7	505.8	527.1	504.5	1,160.3	1,065.7	1,154.4	1,064.3
Georgia	877.5	830.1	873.6	827.0	109.9	103.6	110.3	103.4	226.5	214.6	225.5	213.2	565.5	507.6	566.5	513.3
Hawaii	118.3	112.8	118.0	112.3	10.7	9.5	11.1	9.5	29.6	28.7	29.6	28.6	75.7	73.5	75.3	73.2
Idaho	131.9	121.8	132.5	122.4	11.8	12.2	11.9	12.2	31.8	30.8	31.9	31.1	82.0	74.9	82.8	78.3
Illinois	1,208.1	1,158.4	1,211.0	1,159.9	116.3	108.5	116.3	108.4	394.8	375.3	396.8	377.6	870.5	799.5	875.6	810.5
Indiana	583.9	559.4	585.1	561.0	40.2	39.0	40.4	39.2	136.5	131.9	137.4	134.6	287.7	265.1	289.0	267.8
Iowa	310.5	313.4	311.1	314.6	34.1	32.9	34.0	33.0	102.9	102.6	103.8	104.1	123.4	113.7	124.4	112.9
Kansas	262.7	256.6	264.1	256.5	39.2	37.5	39.2	37.4	73.5	71.2	73.8	71.6	148.5	139.9	149.7	139.0
Kentucky	383.5	369.4	383.8	368.0	30.0	29.3	30.4	28.9	92.4	88.9	92.3	89.8	183.9	172.5	185.2	173.8
Louisiana	383.6	377.7	383.4	378.2	30.9	27.0	31.7	27.5	94.9	92.1	95.7	91.6	206.8	201.7	206.1	202.6
Maine	123.7	117.5	126.0	119.8	10.8	10.2	10.9	10.2	32.9	31.8	33.2	32.3	56.9	56.0	57.8	57.5
Maryland	466.6	447.1	469.7	450.5	50.8	48.7	50.2	48.9	154.1	143.5	154.8	144.3	401.4	399.2	402.9	401.8
Massachusetts	568.9	544.7	576.3	551.8	90.7	85.0	90.6	85.5	221.1	208.9	223.6	210.9	491.5	460.1	497.5	465.3
Michigan	776.6	722.2	780.8	725.9	62.3	56.7	62.5	56.1	207.8	193.0	208.1	194.9	574.0	506.2	570.5	503.0
Minnesota	527.1	504.5	527.8	509.0	57.8	55.9	58.0	55.6	177.0	175.3	178.5	176.8	329.0	298.1	332.3	299.4
Mississippi	224.3	217.3	223.9	217.7	13.5	13.2	13.6	13.2	47.1	44.9	47.2	44.4	95.9	87.3	95.7	86.0
Missouri	545.1	529.6	545.5	530.9	64.4	63.2	64.9	63.6	166.4	162.7	167.1	163.1	343.7	333.2	345.4	332.0
Montana	92.4	89.0	93.0	89.4	7.6	7.3	7.8	7.3	21.9	21.5	22.1	21.8	41.6	39.5	41.9	40.0
Nebraska	205.6	200.3	205.6	200.8	18.8	17.8	18.9	17.8	69.3	68.7	69.7	69.0	106.7	99.2	107.1	100.0
Nevada	231.3	224.6	231.5	225.4	15.9	14.5	15.2	14.3	62.0	58.7	62.0	58.6	156.6	141.6	154.3	139.9
New Hampshire	139.5	138.9	141.5	141.1	12.6	12.1	12.8	12.3	38.2	36.9	38.6	37.6	67.7	65.5	67.8	66.5
New Jersey	865.6	840.8	874.0	850.2	92.7	88.6	93.4	88.2	272.5	258.1	274.2	259.3	619.4	579.3	625.5	582.7
New Mexico	145.1	138.4	144.5	136.6	15.4	15.3	16.4	15.6	34.8	33.6	34.9	32.9	107.6	105.0	108.5	105.5
New York	1,522.9	1,460.5	1,539.1	1,476.6	263.2	252.5	266.0	253.7	722.2	687.9	730.0	690.0	1,159.0	1,116.9	1,173.4	1,123.1
North Carolina	772.0	731.0	773.7	735.4	72.3	67.5	72.4	67.8	212.7	202.6	214.5	201.6	507.1	466.3	509.6	469.8
North Dakota	78.3	79.1	78.1	80.0	7.5	7.2	7.5	7.2	20.2	20.0	20.4	20.4	30.5	29.8	31.0	30.5
Ohio	1,040.6	1,000.1	1,041.1	1,003.2	86.5	79.7	86.5	80.4	292.1	278.9	292.5	281.9	673.8	618.9	676.4	620.8
Oklahoma	289.5	285.7	289.8	285.2	29.3	28.7	29.3	28.7	83.5	80.2	83.6	80.8	185.5	172.9	185.8	171.2
Oregon	335.4	311.4	336.0	310.9	36.3	35.0	36.6	35.3	102.8	95.7	102.6	95.1	197.6	181.0	198.0	181.6
Pennsylvania	1,131.4	1,095.4	1,131.2	1,094.2	108.1	98.3	107.4	98.5	331.1	316.2	333.6	320.1	714.4	675.7	718.6	678.1
Rhode Island	77.5	73.2	78.2	73.9	10.6	10.1	10.8	10.1	33.5	32.2	33.5	32.4	55.3	52.2	56.2	53.1
South Carolina	374.8	360.1	375.2	357.0	28.8	29.8	29.1	29.9	106.6	103.8	107.5	103.7	226.7	212.8	224.7	213.7
South Dakota	82.3	82.2	83.0	82.8	6.9	6.9	7.0	7.0	31.2	29.9	31.6	30.4	28.2	26.6	28.6	27.1
Tennessee	603.1	573.6	602.8	573.7	51.3	47.2	51.3	46.5	145.4	138.6	146.0	137.9	323.4	306.1	326.8	303.4
Texas	2,135.4	2,067.5	2,144.5	2,052.9	219.6	205.7	219.5	204.4	650.3	642.1	652.5	645.8	1,341.3	1,277.1	1,347.3	1,276.3
Utah	247.9	241.0	248.8	240.5	31.4	29.9	31.5	29.8	74.3	71.9	74.2	71.2	164.2	156.8	164.5	156.9
Vermont	59.2	56.6	59.7	57.1	5.8	5.5	5.7	5.5	12.9	12.7	13.0	12.8	23.4	21.3	23.5	21.5
Virginia	657.6	640.8	661.3	642.1	88.3	81.6	88.6	79.9	189.3	186.2	190.6	188.6	656.2	640.4	661.3	637.7
Washington	552.7	527.5	554.7	530.3	104.9	100.7	106.0	101.1	154.2	146.3	154.0	147.8	352.4	327.1	353.6	329.4
West Virginia	141.4	136.2	142.1	136.5	11.2	10.5	11.2	10.3	29.8	28.4	29.9	28.5	61.1	58.9	61.2	58.9
Wisconsin	542.6	511.9	545.8	516.5	50.9	49.3	50.7	49.6	164.8	159.6	165.5	160.1	281.1	257.7	284.2	258.5
Wyoming	55.7	55.3	56.9	56.5	4.0	4.0	4.0	4.1	11.6	11.6	11.8	11.7	18.9	18.1	19.7	18.6
Puerto Rico	180.6	173.1	182.1	171.6	20.6	19.5	20.6	19.2	47.7	43.5	47.9	43.5	107.2	101.6	106.5	101.3

See footnotes at end of table.

ESTABLISHMENT DATA
NOT SEASONALLY ADJUSTED

Table 6. Employees on nonfarm payrolls by state and selected industry sector, not seasonally adjusted—Continued

(In thousands)

State	Education and health services				Leisure and hospitality				Other services				Government			
	May		June		May		June		May		June		May		June	
	2008	2009	2008	2009p	2008	2009	2008	2009p	2008	2009	2008	2009p	2008	2009	2008	2009p
Alabama	211.6	217.3	210.5	215.6	179.8	175.9	180.3	179.1	82.6	76.8	82.7	78.8	388.0	386.4	387.4	384.3
Alaska	37.7	38.8	37.5	38.6	34.7	34.1	38.8	38.2	11.6	11.5	11.7	11.7	85.2	85.8	82.8	83.6
Arizona	320.3	316.4	317.6	315.7	274.9	263.6	269.9	261.2	101.1	93.8	101.3	94.8	441.4	437.6	409.8	398.0
Arkansas	157.6	164.4	156.1	167.7	103.0	104.2	104.5	105.3	46.0	44.1	46.4	45.1	217.6	221.1	211.8	217.0
California	1,736.7	1,756.1	1,720.4	1,737.2	1,592.8	1,528.7	1,609.2	1,538.8	521.1	506.0	523.4	506.5	2,568.3	2,557.3	2,569.8	2,546.3
Colorado	250.2	258.5	249.4	258.6	268.7	255.4	283.6	270.0	94.7	92.1	95.9	92.9	392.6	401.4	382.0	389.1
Connecticut	296.0	301.6	294.3	297.1	142.7	140.9	147.4	146.5	63.7	62.8	64.6	64.5	257.6	254.1	252.3	249.7
Delaware	60.2	61.7	60.1	61.5	42.0	40.4	44.5	43.4	20.5	20.3	20.8	20.6	62.8	63.3	61.5	61.2
District of Columbia	102.1	106.2	97.8	102.8	59.2	59.9	58.8	60.2	65.1	65.1	66.2	66.8	231.3	234.7	234.3	236.5
Florida	1,048.1	1,056.2	1,039.9	1,045.8	967.7	913.6	957.3	910.2	346.8	331.6	346.8	333.9	1,140.4	1,128.3	1,044.4	1,033.1
Georgia	466.3	481.2	458.5	470.5	407.1	396.4	405.1	394.6	162.4	155.4	162.6	156.5	699.0	697.3	686.7	687.6
Hawaii	74.0	75.2	74.6	75.5	108.5	101.4	108.5	101.9	27.6	26.8	27.3	26.5	127.9	130.1	125.9	127.7
Idaho	77.6	78.0	77.8	78.6	64.3	59.9	66.6	62.6	20.9	19.1	21.2	20.2	120.7	123.6	119.7	121.7
Illinois	798.9	805.8	796.1	803.3	548.4	529.6	558.6	541.0	263.1	258.3	268.3	264.2	871.3	869.6	850.2	849.1
Indiana	405.6	417.1	400.6	408.6	294.6	296.1	297.4	301.5	113.8	108.3	114.0	111.1	451.3	450.2	422.3	417.7
Iowa	207.4	210.6	201.5	206.5	140.7	136.1	143.2	140.0	58.1	56.3	58.5	56.1	260.5	260.5	256.1	256.2
Kansas	177.3	178.2	176.6	176.5	119.2	116.8	120.2	117.8	54.0	54.5	53.5	54.4	269.9	272.5	260.3	258.9
Kentucky	244.9	247.0	244.2	247.7	178.5	178.0	178.9	180.1	75.7	74.0	75.7	73.5	327.9	324.5	321.9	318.4
Louisiana	255.1	259.8	254.3	257.1	200.1	199.1	200.4	199.8	69.4	69.8	69.5	70.4	365.2	369.3	360.4	366.8
Maine	118.0	119.6	116.8	118.4	60.7	57.8	68.6	66.5	20.1	19.6	20.3	19.5	107.6	106.0	104.9	103.3
Maryland	382.7	391.9	381.5	390.9	246.8	238.0	254.3	252.1	118.6	115.7	120.0	115.0	494.2	499.8	482.6	487.3
Massachusetts	638.7	648.9	625.8	639.7	313.9	305.8	328.9	326.5	120.4	117.7	124.1	121.3	448.7	446.7	438.7	434.9
Michigan	611.3	616.0	606.1	609.9	414.0	400.5	424.1	412.6	177.6	173.0	179.0	173.0	657.3	659.0	639.8	639.8
Minnesota	442.2	461.4	439.4	455.5	253.3	246.5	261.8	252.4	118.6	115.8	120.4	115.5	428.2	431.0	426.5	429.1
Mississippi	127.8	130.3	125.6	127.8	128.4	124.4	128.3	124.4	37.9	36.6	37.7	38.1	249.4	252.6	245.5	251.5
Missouri	391.6	400.0	390.5	398.5	293.4	285.8	299.0	290.4	121.8	117.5	122.8	118.2	458.6	464.9	446.9	452.9
Montana	61.0	62.0	60.3	62.9	58.8	58.6	63.4	62.9	17.6	17.0	17.9	18.0	90.8	92.6	88.1	92.6
Nebraska	133.0	135.0	131.8	134.8	84.7	84.5	85.8	87.4	35.5	35.2	35.6	35.4	167.8	171.9	166.6	169.7
Nevada	95.9	98.4	95.8	98.3	339.4	316.2	340.0	315.8	37.4	36.8	37.5	37.0	165.5	161.3	160.1	155.4
New Hampshire	105.0	107.2	104.9	106.6	63.6	61.7	69.6	67.3	22.0	22.5	22.4	21.1	97.5	98.3	92.9	97.3
New Jersey	592.7	601.7	593.7	601.6	352.4	341.6	371.8	358.5	167.0	165.3	169.6	171.3	659.0	660.5	662.2	660.7
New Mexico	116.1	119.7	112.8	116.6	87.8	86.2	88.9	86.1	29.8	29.4	32.4	30.6	200.4	202.4	195.7	198.1
New York	1,638.2	1,670.8	1,605.8	1,637.7	732.9	717.0	753.1	745.9	370.5	369.5	371.9	371.4	1,527.6	1,527.5	1,527.1	1,521.2
North Carolina	535.6	544.5	533.6	541.3	409.4	402.0	414.8	407.7	177.7	175.0	179.8	178.6	721.3	732.4	693.4	711.0
North Dakota	52.1	52.8	52.1	53.8	34.1	35.0	34.7	36.4	15.6	15.1	15.5	15.0	79.2	82.0	74.7	76.8
Ohio	816.2	830.2	806.3	818.7	516.5	514.6	526.7	526.5	221.9	217.6	222.9	218.7	814.1	805.1	793.3	780.5
Oklahoma	199.4	200.2	197.8	198.6	146.3	149.1	147.8	151.1	63.5	62.6	63.9	62.2	332.2	337.3	315.2	328.7
Oregon	220.2	226.4	217.5	222.2	175.5	168.9	178.9	172.4	61.7	60.5	61.8	60.5	306.0	310.7	307.3	307.5
Pennsylvania	1,099.7	1,120.2	1,080.1	1,106.9	525.6	509.1	537.7	525.7	255.5	252.3	258.2	253.7	760.7	770.5	745.1	747.8
Rhode Island	101.4	101.1	97.1	97.1	53.0	51.6	55.8	54.7	22.9	22.0	23.2	22.5	65.4	63.6	64.4	62.6
South Carolina	207.4	208.7	206.3	208.7	229.3	212.8	231.4	214.9	72.5	71.7	72.5	73.3	353.0	347.5	348.3	341.9
South Dakota	62.0	63.5	61.8	63.4	44.2	43.8	47.1	46.6	16.0	15.8	16.1	15.9	78.4	79.4	77.0	78.2
Tennessee	356.7	364.0	356.1	365.8	281.5	276.2	284.6	281.2	106.0	102.2	106.3	102.5	434.1	435.6	405.2	418.5
Texas	1,284.9	1,344.5	1,280.1	1,339.0	1,032.1	1,034.5	1,044.1	1,047.1	364.2	358.7	367.5	361.4	1,801.3	1,838.2	1,766.4	1,807.0
Utah	143.1	147.4	142.7	146.2	114.2	109.8	116.8	113.2	35.7	33.3	36.0	33.5	214.3	220.7	213.6	219.9
Vermont	59.1	60.2	58.0	59.8	29.9	27.7	32.4	30.3	9.9	9.4	10.0	9.6	56.2	56.4	53.1	53.6
Virginia	441.7	444.1	440.4	449.1	361.6	357.6	372.2	367.2	189.6	184.9	190.7	186.0	699.6	709.6	696.0	699.6
Washington	363.5	368.2	359.9	362.7	287.2	290.2	293.8	298.2	108.1	106.6	108.8	108.2	552.8	559.2	553.2	556.1
West Virginia	116.5	118.1	116.1	117.7	74.1	72.3	75.0	73.4	56.2	55.6	56.3	55.6	150.2	149.9	144.3	145.3
Wisconsin	404.5	413.6	404.6	412.6	267.6	258.7	276.9	275.2	139.1	134.5	140.7	134.2	432.5	439.8	421.9	429.5
Wyoming	24.2	24.7	24.6	25.1	34.1	32.8	38.8	37.8	12.2	11.9	12.3	12.2	71.4	72.9	71.3	72.7
Puerto Rico	112.2	111.6	106.3	105.9	74.0	72.6	73.9	72.3	16.9	15.5	16.7	15.5	296.0	299.0	316.4	314.1

[1] Mining and logging is combined with construction.
p = preliminary.
NOTE: Data are counts of jobs by place of work. Estimates are currently projected from 2008 benchmark levels. Estimates subsequent to the current benchmarks are provisional and will be revised when new information becomes available.

Chart 1. Unemployment rates by state, seasonally adjusted, June 2009

(U.S. rate = 9.5 percent)

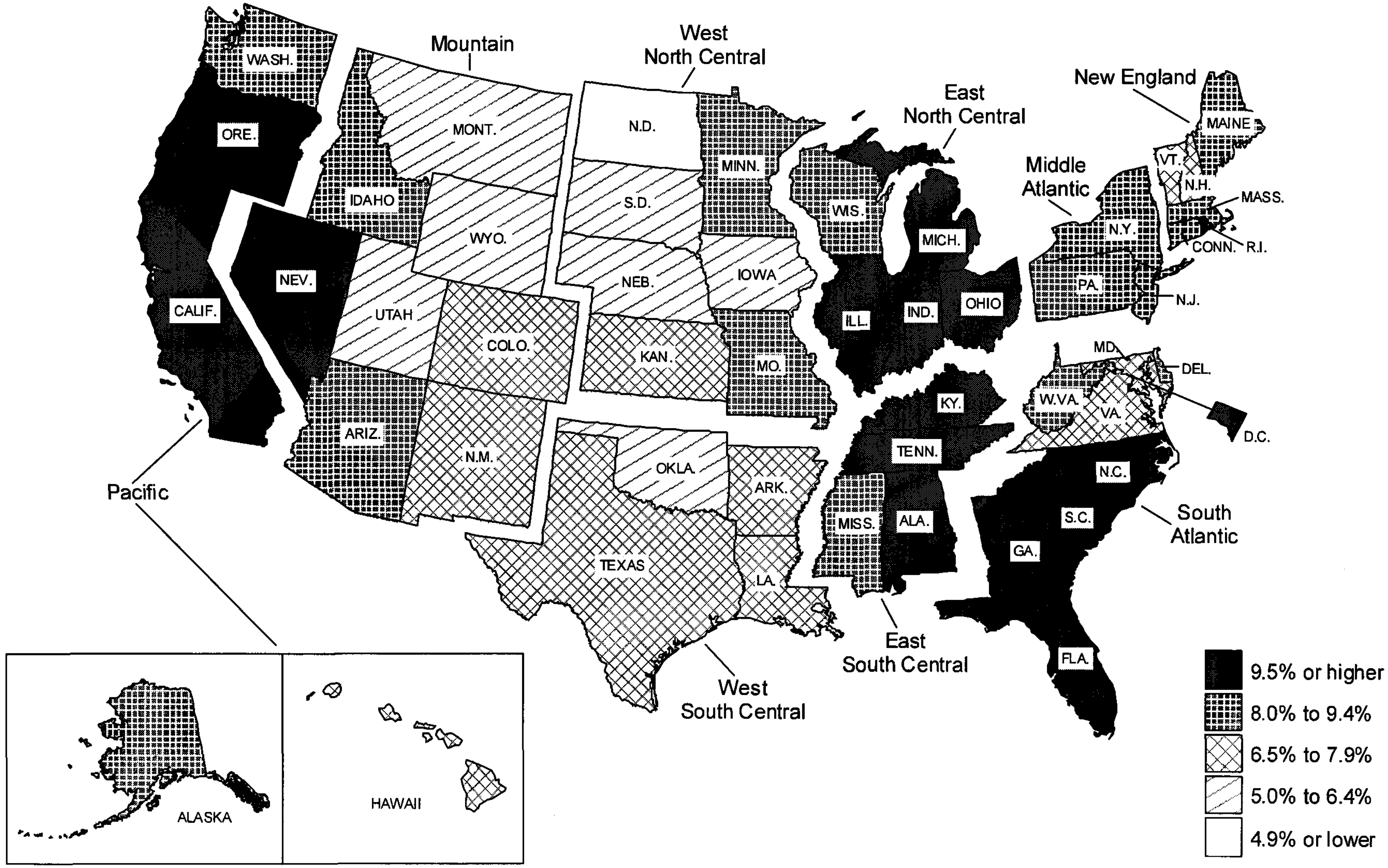
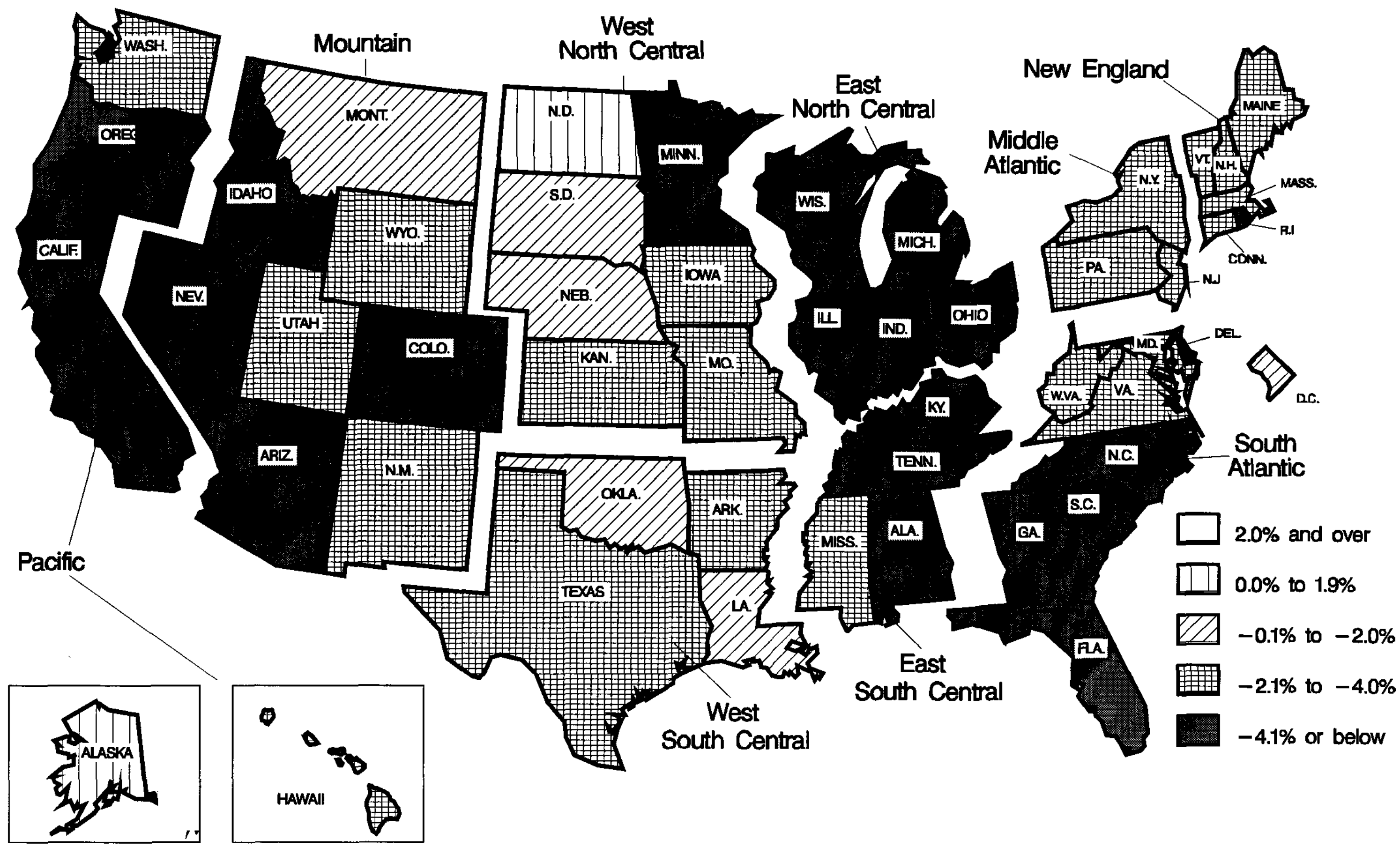


Chart 2. Percentage change in nonfarm employment by state, seasonally adjusted, June 2008 – June 2009



EXHIBIT
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R-18
ADMITTED

U.S. FORECLOSURE ACTIVITY INCREASES 7 PERCENT IN JULY

By RealtyTrac Staff

U.S. Foreclosure Activity Up 32 Percent from July 2008
Over 360,000 Households Receive Foreclosure Filings, Setting New Record

IRVINE, Calif. — August 13, 2009 — RealtyTrac® (www.realtytrac.com), the leading online marketplace for foreclosure properties, today released its July 2009 U.S. Foreclosure Market Report™, which shows foreclosure filings — default notices, scheduled auctions and bank repossessions — were reported on 360,149 U.S. properties during the month, an increase of nearly 7 percent from the previous month and an increase of 32 percent from July 2008. The report also shows that one in every 355 U.S. housing units received a foreclosure filing in July.

"July marks the third time in the last five months where we've seen a new record set for foreclosure activity," noted James J. Saccacio, chief executive officer of RealtyTrac. "Despite continued efforts by the federal government and state governments to patch together a safety net for distressed homeowners, we're seeing significant growth in both the initial notices of default and in the bank repossessions."

View U.S. foreclosure heat map and comment on this report.

Nevada, California, Arizona post top state foreclosure rates
For the 31st consecutive month Nevada documented the nation's highest state foreclosure rate, with one in every 56 housing units receiving a foreclosure filing in July — more than six times the national average. Initial default notices (NOD) in Nevada decreased 18 percent from the previous month, likely the result of a new state law requiring lenders to offer mediation to homeowners facing foreclosure. The law took effect July 1. Meanwhile, scheduled auctions (NTS) and bank repossessions (REO) in Nevada both increased more than 20 percent from the previous month, boosting overall foreclosure activity in the state by 4 percent on a month-over-month basis.

Initial defaults (NOD) in California spiked 15 percent from the previous month, and the state registered the nation's second highest state foreclosure rate for the third month in a row. One in every 123 California housing units received a foreclosure filing in July, nearly three times the national average. Scheduled auctions (NTS) in California were down 1 percent from the previous month, but bank repossessions (REO) were up 4 percent — leaving overall foreclosure activity up nearly 7 percent on a month-over-month basis.

One in every 135 Arizona housing units received a foreclosure filing in July, the nation's third highest state foreclosure rate and more than 2.5 times the national average. Scheduled auctions (NTS), the first public record in the Arizona foreclosure process, jumped 25 percent from the previous month while bank repossessions stayed flat.

Other states with foreclosure rates ranking among the nation's 10 highest were Florida, Utah, Idaho, Georgia, Illinois, Colorado and Oregon.

Four states account for more than half of total foreclosure activity
The top four state foreclosure activity totals in July were reported by California, with 108,104 properties receiving a foreclosure filing; Florida, with 56,486 properties receiving a foreclosure filing; Arizona, with 19,694 properties receiving a foreclosure filing; and Nevada, with 19,535 properties receiving a foreclosure filing. Together these four states accounted for nearly 57 percent of the nation's total foreclosure activity.

Although Florida bank repossessions (REO) decreased 8 percent from the previous month, the state's overall foreclosure activity was still up 7 percent from the previous month because of a 9 percent month-over-month increase in both initial default notices (LIS) and scheduled auctions (NFS).

Illinois registered the fifth highest state foreclosure activity total, with 14,524 properties receiving a foreclosure filing during the month. Overall foreclosure activity in Illinois increased nearly 35 percent from the previous month, boosted by an 86 percent surge in default notices (LIS), which bounced back from low levels in May and June. A state law enacted April 5 gave delinquent borrowers an extension of up to 90 days before the start of the foreclosure process.

Other states with totals among the 10 highest in the country were Texas (12,077), Georgia (11,136), Ohio (11,021), Michigan (8,257) and New Jersey (6,467).

Foreclosure activity in Michigan dropped 39 percent from the previous month, mostly due to a 66 percent decrease in scheduled auctions (NTS. A state law that took effect July 6 requires lenders — before scheduling a foreclosure auction — to provide delinquent borrowers a uniform default notice with contact information for approved housing counselors who can assist in loan modification. The law freezes foreclosure proceedings an extra 90 days for homeowners who commit to work on a loan modification plan.

Four states dominate top 10 metro foreclosure rates
Foreclosure filings were reported on 16,798 Las Vegas properties in July, one in every 47 housing units — more than 7.5 times the national average and the highest foreclosure rate among metro areas with a population of at least 200,000. The city's foreclosure activity increased nearly 6 percent from the previous month and 89 percent from July 2008.

Seven California metro areas documented foreclosure rates among the top 10 in July. Stockton posted the nation's second highest metro foreclosure rate — one in every 62 housing units received a foreclosure filing — followed by Modesto at No. 3 (one in 63), Merced at No. 5 (one in 66), Riverside-San Bernardino-Ontario at No. 6 (one in 67), Bakersfield at No. 7 (one in 76), Vallejo-Fairfield at No. 8 (one in 83), and Sacramento-Arden-Arcade-Roseville at No. 10 (one in 105).

Other cities with top 10 metro foreclosure rates were Cape Coral-Fort Myers, Fla., at No. 4, with one in every 64 housing units receiving a foreclosure filing, and Phoenix-Mesa-Scottsdale, Ariz., at No. 9, with one in every 103 housing units receiving a foreclosure filing.

Report methodology
The RealtyTrac U.S. Foreclosure Market Report provides a count of the total number of properties with at least one foreclosure filing reported during the month — broken out by type of filing at the state and national level. Data is also available at the individual county level. Data is collected from more than 2,200 counties nationwide, and those counties account for more than 90 percent of the U.S. population. RealtyTrac's report incorporates documents filed in all three phases of foreclosure:
Default — Notice of Default (NOD) and Lis Pendens (LIS);
Auction — Notice of Trustee Sale and Notice of Foreclosure Sale (NTS and NFS); and
Real Estate Owned, or REO properties (that have been foreclosed on and repurchased by a bank).
If more than one foreclosure document is filed against a property during the month, only the most recent filing is counted in the report. The report also checks if the same type of document was filed against a property in a previous month. If so, and if that previous filing occurred within the estimated foreclosure timeframe for the state the property is in, the report does not count the property in the current month.

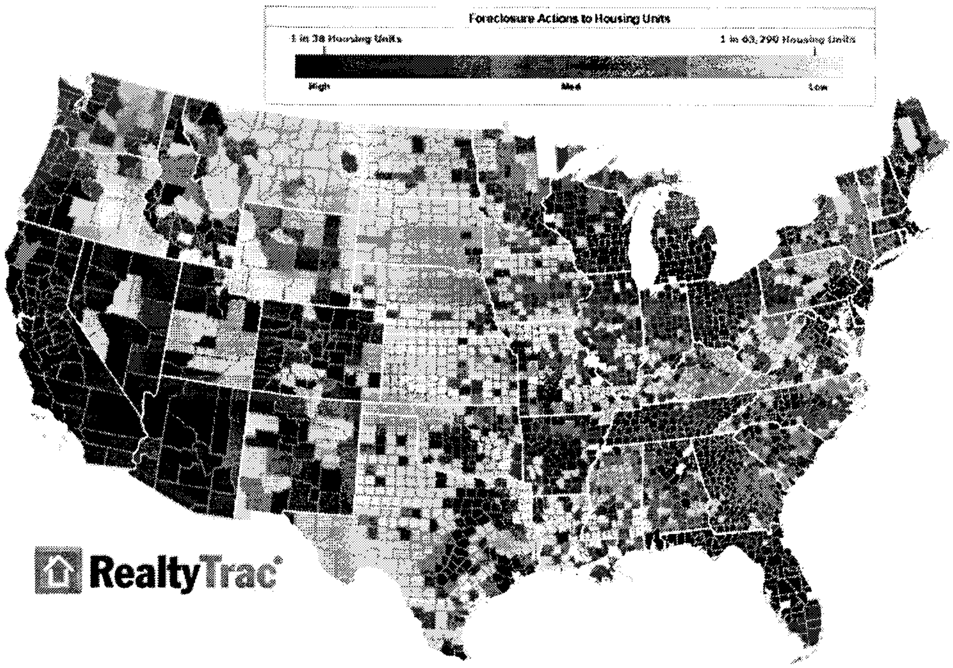
U.S. Foreclosure Market Data by State – July 2009
Properties with Foreclosure Filings

Rate Rank	State Name	NOD	LIS	NTS	NFS	REO	Total	1/every X HU (rate)	%? from Jun 09	%? from Jul 08
--	**U.S.**	**62,939**	**71,565**	**104,830**	**33,557**	**87,258**	**360,149**	**355**	**6.74**	**32.32**
33	Alabama	0	0	1,630	0	452	2,082	1,026	-23.34	141.25*
24	Alaska	3	0	266	0	102	371	761	76.67	79.23
3	Arizona	2	0	14,120	0	5,572	19,694	135	16.99	47.52
21	Arkansas	104	0	1,319	0	828	2,251	572	35.03*	110.77*
2	California	50,917	0	35,802	0	21,385	108,104	123	6.99	49.55
9	Colorado	5	0	3,947	0	1,536	5,488	388	-4.12	2.08
29	Connecticut	0	1,084	0	190	295	1,569	917	7.84	-22.10
37	Delaware	0	0	0	226	72	298	1304	-12.61	125.76
	District of Columbia	267	0	219	0	35	521	546	24.94	-6.80
4	Florida	0	35,227	0	14,502	6,757	56,486	154	6.78	23.11
7	Georgia	1	0	7,616	0	3,519	11,136	356	-20.59	10.68
15	Hawaii	186	0	481	0	323	990	512	40.23	332.31
6	Idaho	1,290	0	1,051	0	150	2,491	253	32.43*	166.13*
8	Illinois	0	6,770	0	4,060	3,694	14,524	361	34.53	62.92
17	Indiana	0	1,015	0	1,881	2,290	5,186	536	-6.86	8.43
43	Iowa	0	0	227	0	374	601	2,212	7.32	20.68
30	Kansas	0	183	0	408	728	1,319	925	37.68	94.83
39	Kentucky	0	405	0	488	341	1,234	1,545	9.30	0.65
40	Louisiana	0	6	0	928	183	1,117	1,664	-23.07	9.83
41	Maine	0	138	0	212	57	407	1,712	39.38	59.61
11	Maryland	0	3,521	0	633	998	5,152	450	66.19	65.98

16	Massachusetts	0	3,548	0	1,049	517	5,114	532	58.77	43.09
19	Michigan	1	0	2,695	0	5,561	8,257	548	-39.32	-28.76
20	Minnesota	12	0	2,266	0	1,847	4,125	559	23.80	146.86
45	Mississippi	0	0	354	0	124	478	2,625	-36.69	151.58*
27	Missouri	5	0	1,729	0	1,441	3,175	834	2.02	-9.60†
47	Montana	0	0	2	0	88	90	4,839	45.16	-36.62
46	Nebraska	0	164	0	5	26	195	4,004	30.87	-70.45
1	Nevada	7,139	0	7,833	0	4,563	19,535	56	4.11	94.18
31	New Hampshire	0	0	611	0	12	623	954	42.24	-31.01
18	New Jersey	0	4,210	0	1,505	752	6,467	541	49.25	39.92
32	New Mexico	0	479	0	270	128	877	983	23.52	61.21*
38	New York	0	4,613	0	871	470	5,954	1,334	22.76	-3.45
36	North Carolina	1,120	0	756	0	1,552	3,428	1,203	7.97	-20.33
48	North Dakota	0	1	0	26	23	50	6,211	56.25	-23.08
12	Ohio	0	5,062	0	3,032	2,927	11,021	460	-2.05	-18.10
35	Oklahoma	595	0	522	0	420	1,537	1,056	18.69	-11.05
10	Oregon	29	0	2,463	0	1,113	3,605	446	15.80	84.40
34	Pennsylvania	0	1,869	0	1,805	1,642	5,316	1,030	7.59	27.36*
28	Rhode Island	0	0	17	0	488	505	893	-44.63	2.23
26	South Carolina	0	1,209	0	484	735	2,428	833	44.01	82.15*
42	South Dakota	0	60	0	56	48	164	2,178	45.13	446.67*
22	Tennessee	0	0	2,263	0	2,309	4,572	596	-2.20	0.15††
25	Texas	24	0	7,194	0	4,859	12,077	781	0.45	16.64
5	Utah	1,234	0	1,728	0	732	3,694	250	6.42	93.30
50	Vermont	0	0	0	0	11	11	28,312	0.00	120.00
14	Virginia	5	0	3,927	0	2,474	6,406	511	23.48	11.51†
13	Washington	0	0	3,632	0	1,738	5,370	511	14.79	94.42*
49	West Virginia	0	0	119	0	20	139	6,350	21.93	265.79
23	Wisconsin	0	2,001	0	926	890	3,817	671	8.10	86.74*
44	Wyoming	0	0	41	0	57	98	2,473	16.67	-26.32

* Actual increase may not be as high due to data collection changes or improvements
† Collection of some records previously classified as NOD in this state was discontinued starting in January 2009
† Collection of some records previously classified as NOD in this state was discontinued starting in September 2008

U.S. Foreclosure Rates Heat Map – July 2009



About RealtyTrac Inc.

RealtyTrac® (www.realtytrac.com) is the leading online marketplace of foreclosure properties, with more than 1.5 million default, auction and bank-owned listings from over 2,200 U.S. counties, along with detailed property, loan and home sales data. Hosting more than 3 million unique monthly visitors, RealtyTrac provides innovative technology solutions and practical education resources to facilitate buying, selling and investing in real estate. RealtyTrac's foreclosure data has also been used by the Federal Reserve, FBI, U.S. Senate Joint Economic Committee and Banking Committee, U.S. Treasury Department, and numerous state housing and banking departments to help evaluate foreclosure trends and address policy issues related to foreclosures.

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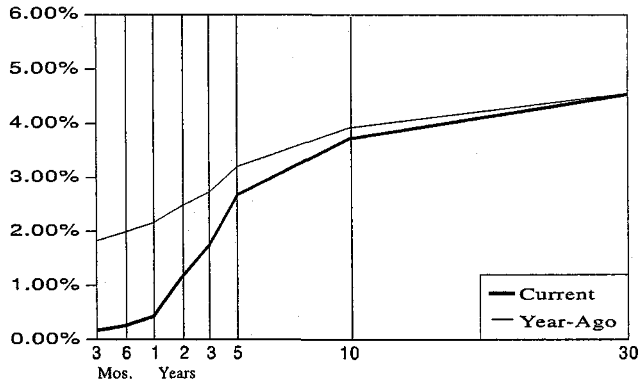
EXHIBIT R-19 ADMITTED

Selected Yields

	Recent (8/12/09)	3 Months Ago (5/13/09)	Year Ago (8/13/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.25	0.32	2.74
3-month LIBOR	0.45	0.88	2.80
Bank CDs			
6-month	0.50	0.73	1.60
1-year	0.73	0.98	2.26
5-year	1.90	1.93	4.16
U.S. Treasury Securities			
3-month	0.17	0.17	1.83
6-month	0.26	0.28	1.99
1-year	0.43	0.50	2.16
5-year	2.68	1.98	3.20
10-year	3.72	3.12	3.93
10-year (inflation-protected)	1.83	1.64	1.68
30-year	4.54	4.10	4.56
30-year Zero	4.65	4.18	4.61

	Recent (8/12/09)	3 Months Ago (5/13/09)	Year Ago (8/13/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.83	3.09	5.84
FHLMC 6.5% (Gold)	3.19	2.38	5.87
FNMA 6.5%	2.91	2.20	5.79
FNMA ARM	2.75	2.78	4.02
Corporate Bonds			
Financial (10-year) A	6.45	6.94	6.20
Industrial (25/30-year) A	5.85	6.19	6.29
Utility (25/30-year) A	5.79	6.01	6.27
Utility (25/30-year) Baa/BBB	6.62	7.57	6.75
Foreign Bonds (10-Year)			
Canada	3.52	3.10	3.61
Germany	3.46	3.34	4.21
Japan	1.43	1.46	1.46
United Kingdom	3.79	3.52	4.60
Preferred Stocks			
Utility A	5.66	6.35	6.27
Financial A	6.06	8.65	7.37
Financial Adjustable A	5.51	5.51	5.51

Treasury Security Yield Curve



	Recent (8/12/09)	3 Months Ago (5/13/09)	Year Ago (8/13/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.65	4.63	4.75
25-Bond Index (Revs)	5.68	5.57	5.23
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.43	1.56
1-year A	1.10	1.16	1.66
5-year Aaa	1.69	1.82	2.90
5-year A	3.09	3.24	3.00
10-year Aaa	2.98	2.86	3.68
10-year A	4.50	4.41	3.88
25/30-year Aaa	4.66	4.43	4.75
25/30-year A	6.17	5.91	5.10
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.90	5.96	5.00
Electric AA	5.95	6.06	5.05
Housing AA	6.45	6.36	5.20
Hospital AA	6.45	6.31	5.20
Toll Road Aaa	5.90	6.11	5.10

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	7/29/09	7/15/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	728856	743860	-15004	777896	755940	557494
Borrowed Reserves	347217	387829	-40612	451108	519244	495733
Net Free/Borrowed Reserves	381639	356031	25608	326788	236696	61761

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	7/27/09	7/20/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1647.6	1644.8	2.8	19.0%	13.0%	16.9%
M2 (M1+savings+small time deposits)	8365.7	8341.1	24.6	3.1%	2.3%	8.1%

EXHIBIT
R-2D
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-04204A-08-0571

REDACTED DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 8, 2009

TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-08-0571
TESTIMONY OF STAFF WITNESS RALPH C. SMITH

My testimony addresses the following issues, and responds to the testimony of UNS Gas, Inc. ("UNSG", "UNS Gas," or "Company") witnesses on these issues:

- The Company's proposed revenue requirement
- The determination of a Fair Value Rate of Return and its application to Fair Value Rate Base
- RUCO's recommended base revenue increase
- Adjusted Rate base
- Adjusted Test year revenues, expenses, and net operating income

My findings and recommendations for each of these areas are as follows:

The Company's Proposed Revenue Requirement
The Company's proposed revenue requirement of a base rate increase of $9.480 million, or 18.53 percent, is significantly overstated. In its filing, UNSG calculated the same revenue deficiency on its proposed original cost rate base (OCRB) and fair value rate base (FVRB).

UNSG overstated rate base and understated operating income. Additionally, the Company is requesting an excessive rate of return.

UNSG's request for a 9.54 percent overall return on OCRB could be viewed as effectively requesting a return on equity of 12.58 percent on OCRB, as shown on my Attachment RCS-2, Schedule D, page 1, and summarized below:

UNS Gas Proposed to Show Equivalent Requested ROE

Capital Source	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
Long-Term Debt	50.01%	6.49%	3.25%
Common Stock Equity	49.99%	**12.58%**	6.29%
Overall Cost of Capital	100.00%		9.54%

The testimony of RUCO witness William Rigsby addresses RUCO's recommended return on equity and weighted cost of capital to be applied to OCRB.

The Determination of a Fair Value Rate of Return (FVROR) and its Application to FVRB
The Commission's traditional calculation of return on fair value rate base calculation has been called into question by a recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income in that case had ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

That Court of Appeals decision provided some guidance for calculating the return on fair value rate base. For example, at pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision stated that: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

The Commission reopened Docket No. W-02113A-04-0616 to address such issues in a Chaparral City remand proceeding and, on July 28, 2008, issued Decision No. 70441. In Decision No. 70441, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the Commission can use to determine an appropriate FVROR, including adjusting the weighted average cost of capital ("WACC") to exclude the effect of inflation on the cost of equity, and that the FVROR adopted there fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process.

My direct testimony in the instant rate case describes RUCO's derivation of the fair value return on fair value rate base calculations in view of the Court of Appeals decision concerning Chaparral and the Commission's Decision No. 70441 in the Chaparral remand case, as described above. Attachment RCS-2, Schedule D, page 2, shows the derivation of four FVROR calculations that were considered by RUCO, including:

- Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation
- Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation
- Calculation 3 - With Fair Value Rate Base Increment at Zero Cost
- Calculation 4 - With Fair Value Rate Base Increment at 1.25 Percent

My Attachment RCS-2, Schedule A, page 2, in columns A through D, summarizes the resulting revenue deficiencies that would be produced in the current UNSG rate case from each of those FVROR figures, and in Column E shows RUCO's recommended FVROR of 5.38 percent. RUCO's recommendation falls within the range of FVRORs developed using various calculation methods, and is near, but not at the low end of that range. I believe that this information and RUCO's recommended FVROR in the current UNSG rate case that was made after considering these alternatives appropriately fulfills the requirement of the Arizona Constitution that the Commission must base rates on a utility's fair value.

My Attachment RCS-2, Schedule A, page 1, Column D, shows the amount of base rate revenue increase on FVRB of $841,000.

Recommended Base Rate Revenue Increase

On original cost rate base (OCRB) my calculations show a jurisdictional revenue deficiency of $803,000 and $841,000 on FVRB, based on a FVROR of 5.38 percent. I recommend that UNSG be authorized a base rate increase of no more than $841,000 on adjusted FVRB. That is an average revenue increase of approximately 1.63 percent over adjusted test year revenue of $51.674 million.

Adjusted Rate Base

The following adjustments to UNSG's proposed original cost rate base should be made:

Summary of RUCO Adjustments to Rate Base

Adj. No.	Description	Increase (Decrease)	Note
B-1	Construction Work in Progress/Post Test Year Plant	$ (1,527,588)	
B-2	Customer Advances	$ (589,152)	
B-3	Prepayments	$ (95,671)	
B-4	Cash Working Capital	$ -	[a]
B-5	Customer Deposits	$ -	[a]
B-6	Accumulated Deferred Income Taxes	$ (196,256)	
	Total of RUCO Adjustments	$ (2,408,667)	
	UNS Proposed Rate Base (Original Cost)	$ 182,293,106	
	RUCO Proposed Rate Base (Original Cost)	$ 179,884,439	

[a] Schedule is a placeholder for a potential adjustment to be submitted in a later stage filing, such as surrebuttal

The following table summarizes UNS Gas' requested and RUCO's recommend OCRB, reconstruction cost new depreciated (RCND) rate base and FVRB, and the differences:

Summary of Rate Base	UNS Gas	RUCO	Difference
Original Cost Rate Base	$ 182,293,106	$ 179,884,439	$ (2,408,667)
RCND Rate Base	$ 329,266,770	$ 325,871,264	$ (3,395,506)
Fair Value Rate Base	$ 255,779,939	$ 252,877,851	$ (2,902,088)

Adjusted Net Operating Income

The following adjustments to UNSG's proposed revenues, expenses and net operating income should be made:

Summary of RUCO Adjustments to Net Operating Income

Adj No.	Description	Pre-Tax Operating Income or Expense Adjustment	Net Operating Income Adjustment
C-1	Gas Retail Revenue	$ 516,003	$ 316,836
C-2	Depreciation & Property Taxes for CWIP	$ 95,042	$ 58,358
C-3	Incentive Compensation	$ 152,511	$ 93,645
C-4	Stock-Based Compensation Expense	$ 266,399	$ 163,574
C-5	Supplemental Executive Retirement Plan Expense	$ 101,021	$ 62,029
C-6	American Gas Association Dues	$ 16,762	$ 10,292
C-7	Outside Services Legal Expense	$ 217,674	$ 133,656
C-8	Fleet Fuel Expense	$ 471,826	$ 289,711
C-9	Rate Case Expense	$ 158,333	$ 97,220
C-10	Interest Synchronization	$ -	$ (30,215)
C-11	Property Tax Expense	$ 230,913	$ 141,785
C-12	2010 Pay Increase	$ 250,622	$ 153,887
Total of RUCO's Adjustments to Net Operating Income		$ 2,477,106	$ 1,490,778
	Company Proposed Net Operating Income	$ -	$ 11,600,004
	Rounding	$ -	$ -
	Adjusted Net Operating Income per RUCO		$ 13,090,782

I. INTRODUCTION

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

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("C.P.A.") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed C.P.A. and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July, 1979. Before becoming involved in utility regulation where the majority of my time for the past 29 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, 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 D.C., West

Virginia and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Residential Utility Consumer Office ("RUCO").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have previously testified before the Commission on a number of occasions. I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS" or "Company"), and APS' Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, concerning proceedings involving APS base rates and other matters. I also testified before the Commission in the last UNS Gas, Inc. rate case, Docket Nos. G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831, and in the last UNS Electric, Inc. rate case Docket No. E-04204A-06-0783, as well as the last Southwest Gas Corporation rate case, G-01551A-07-0504.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the rate base, adjusted net operating income and revenue requirement proposed by UNS Gas, Inc. ("UNSG", "UNS Gas," or "Company").

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 through RCS-6 contain the results of my analysis and copies of selected documents that are referenced in my testimony, respectively.

II. REVENUE REQUIREMENT

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed revenue requirement and selected other issues.

Q. What revenue increase has been requested by UNSG?

A. UNSG is requesting an increase in base rate revenues of $9.480 million, or approximately 6.1% percent, based on adjusted gas retail revenues at current rates of $51.158 million. The revenue amount is from Company Schedule C-1 in UNSG's filing and is also shown on RUCO Schedule C on Attachment RCS-2.

Q. What revenue increase does RUCO recommend?

A. RUCO recommends a revenue increase of no more than $841,000 on adjusted fair value rate base. As shown on Schedule A, on original cost rate base (OCRB) my calculations show a jurisdictional revenue deficiency of $803,000.

A. Test Year

Q. What test year is being used in this case?

A. UNSG's filing is based on the historic test year ended June 30, 2008. RUCO's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, are based on a test year average level. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are annualized based on end of test year levels. This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

B. Summary of Company Proposed and RUCO Adjusted Revenue Requirement

Q. What did your review of UNSG's filing indicate?

A. As shown on Attachment RCS-2, Schedule A, column C, based on the weighted cost of capital recommended by RUCO witness William Rigsby for application to OCRB, and the adjustments to UNSG's rate base and net operating income recommended by myself, I have calculated a jurisdictional base rate revenue requirement deficiency on OCRB of $803,000. As also shown on Schedule A, page 1, column D, I have calculated a recommended base rate increase of $841,000 using a fair value rate of return (FVROR) of

5.38. UNSG should receive a base rate increase of no more than $841,000 in this case. This represents an overall increase of approximately 1.63 percent.

C. Organization of RUCO Accounting Schedules

Q. How are RUCO's accounting schedules organized?

A. RUCO's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-6[1] and net operating income adjustment Schedules C-1 through C-12.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the RUCO Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony. This schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn RUCO's recommended rate of return on RUCO's proposed Original Cost and Fair Value rate bases. The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return on original cost rate base of 7.55 percent, as presented in the prefiled testimony of RUCO witness Rigsby, is provided on Schedule D for convenience, as are the derivation of RUCO's recommended fair value rate of return.

Columns A and B of Schedule A replicate UNSG's proposed calculations of the revenue deficiency. Columns C and D of Schedule A presents RUCO's determination of

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[1] Currently, RUCO Adjustments B-4 and B-5 are placeholders, i.e., schedules reserved for an adjustment to be calculated at a later stage of proceeding, if necessary

the base rate revenue deficiency on OCRB and FVRB. Column C reflects Mr. Rigsby's recommended overall weighted cost of capital for OCRB. Column D uses RUCO's proposed fair value rate of return, which is explained in my testimony.

The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross revenue requirement, which is obtained by multiplying the income deficiency by the gross revenue conversion factor (GRCF). The derivation of the GRCF is shown on Schedule A-1.

Q. What is shown on page 2 of Schedule A?

A. Page 2 of Schedule A shows information concerning the potential impacts on UNSG's revenue deficiency in the current rate case that was considered by RUCO in developing the recommended FVROR recommendation. Similar to information presented by RUCO and Staff to the Commission in a recent remand proceeding, Docket No. W-02113A-04-0616, concerning Chaparral City Water Company, and in some other recent rate cases, I have also presented on Schedule A, page 2, in columns A through D various potential ways of determining a FVROR for UNSG, including:

- Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation
- Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation
- Calculation 3 - With Fair Value Rate Base Increment at Zero Cost
- Calculation 4 - With Fair Value Rate Base Increment at 1.25%

The details for each FVROR calculation are shown on Schedule D, page 2.

On Schedule A, page 2, in column E, I also present RUCO's ultimate recommendation of the FVROR and the resulting base rate revenue deficiency. RUCO's recommendation falls within the range of FVRORs developed using various calculation methods, and is near, but not at the low end of that range. I believe that this information and RUCO's recommended FVROR in the current UNSG rate case that was made after considering these alternatives appropriately fulfills the requirement of the Arizona Constitution that the Commission must base rates on a utility's fair value.

Q. What is shown on Schedule A-1?

A. Schedule A-1 shows the derivation of the GRCF. The GRCF is used to convert the net operating income deficiency into a revenue deficiency amount.

Q. How does the GRCF recommended by RUCO compare with the GRCF contained in UNSG's filing?

A. As shown on Schedule A-1, RUCO recommends a GRCF of 1.636582. Other than carrying out two extra decimal places for slightly improved accuracy, this is essentially the same as the GRCF of 1.6366 used in UNSG's filing.

Q. What is shown on Schedule B?

A. Schedule B presents UNSG's proposed adjusted test year Original Cost and Fair Value rate base and RUCO's proposed adjusted test year Original Cost and Fair Value rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically UNSG Schedule B-1. RUCO's recommended adjustments to rate base are summarized on Schedule B.1. I have prepared a Schedule B.1 for adjustments to UNSG's proposed original cost rate base. Because there is only one adjustment that differs between OCRB and Reconstruction Cost New Depreciated (RCND) rate base, I have only prepared one Schedule B.1, which shows OCRB amounts.

I address the difference in the OCRB and RCND amount used by the Company for CWIP/post test year plant in a subsequent section of my testimony.

Schedules B-1 through B-6 provide further support and calculations for the rate base adjustments RUCO is recommending.

Q. How was the fair value basis of rate base determined?

A. As shown on Attachment RCS-2, Schedule B, the fair value rate base was determined by averaging Original Cost and Reconstruction Cost New Depreciated (RCND) rate base information. For purposes of this presentation, I have used the Company's OCRB and RCND information as the starting point for RUCO's derivation of the fair value rate base.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is UNSG's adjusted test year net operating income, as provided on Company Schedule C-1. RUCO's recommended adjustments to UNSG's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of the adjustments are discussed in my testimony.

Schedules C-1 through C-12 provide further support and calculations for the net operating income adjustments RUCO is recommending.

Q. What is shown on Schedule D?

A. Schedule D, page 1, summarizes the capital structure and cost of capital that was proposed by UNSG and the capital structure and cost of capital that is recommended by RUCO witness Rigsby. As noted above, Schedule D, page 2, also presents four alternative calculations of a FVROR that were considered by RUCO in developing RUCO's recommended FVROR for use with the RUCO's adjusted fair value rate base.

Q. What is shown on Schedule D, page 1, lines 7-10?

A. On its Schedule D-1, UNSG purported to be requesting a return on equity ("ROE") of 11.0 percent, and an overall rate of return of 8.75 percent. However, on its Schedule A-1, line 7, UNSG has applied an overall rate of return of 9.54 percent to its proposed OCRB. On Schedule D, I have shown a calculation based on the capital structure UNSG used for developing its recommended rate of return of 9.54 percent on OCRB. This calculation shows that the equivalent return on equity ("ROE") implicit in UNSG's request for 9.54 percent on OCRB is an ROE of 12.58 percent, as summarized below:

UNS Gas Proposed to Show Equivalent Requested ROE

Capital Source	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
Long-Term Debt	50.01%	6.49%	3.25%
Common Stock Equity	49.99%	**12.58%**	6.29%
Overall Cost of Capital	100.00%		9.54%

D. Return on Fair Value Rate Base

Q. Has the Commission's traditional calculation of return on fair value rate base been called into question by a recent Court of Appeals decision?

A. Yes. The Commission's traditional calculation of return on fair value rate base calculation has been called into question by a recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income in that case had ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

Q. What guidance for calculating the return on fair value rate base does that Court of Appeals decision provide?

A. First, the Court of Appeals specifically stated that the Commission was <u>not</u> bound to apply an authorized rate of return that was developed for use with an original cost rate base, without adjustment, to the fair value rate base. Page 9 of the Court of Appeals decision stated that: "Chaparral City ... asks that the Commission be directed to apply the 'authorized rate of return' to the fair value rate base rather than to the OCRB, as Chaparral City contends was done here." At page 13, paragraph 17, the Court of Appeals decision stated as follows: "The Commission asserts that it was not bound to use the weighted average cost of capital as the rate of return to be applied to the FVRB. The Commission is correct." Thus, the Court of Appeals clearly stated that the Commission is <u>not</u> bound to apply to the FVRB the same weighted average cost of capital that was developed for application to the OCRB.

At pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision states: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

Q. Was a remand proceeding established by the Commission to address the calculation of the return on fair value rate base, i.e., to address the ruling in the Court of Appeals decision?

A. Yes. The Commission reopened Docket No. W-02113A-04-0616 to address such issues in a Chaparral City remand proceeding and, on July 28, 2008, issued Decision No. 70441. In Decision No. 70441, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the

Commission can use to determine an appropriate FVROR, including adjusting the weighted average cost of capital ("WACC") to exclude the effect of inflation on the cost of equity, and that the adopted FVROR fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process.[2]

Q. How has RUCO addressed the ruling in the Court of Appeals decision for purposes of the current UNSG rate case?

A. In view of the Court of Appeals decision in the Chaparral City case, RUCO has appropriately adjusted the weighted cost of capital to derive a FVROR to apply to the utility's FVRB. My direct testimony in the instant rate case describes RUCO's derivation of the fair value return on fair value rate base calculations in view of the Court of Appeals decision concerning Chaparral and the Commission's Decision No. 70441 in the Chaparral remand case, as described above.[3] My Attachment RCS-2, Schedule D, page 2, shows the derivation of four FVROR calculations that were considered by RUCO. My Attachment RCS-2, Schedule A, page 2, in columns A through D, summarizes the resulting revenue deficiencies that would be produced in the current UNSG rate case from each of those FVROR figures. Schedule A, page 2, Column E shows RUCO's recommended FVROR and the resulting revenue deficiency. This FVROR recommendation was also applied to the FVRB on Schedule A, page 1, column D.

III. RATE BASE

Q. Have you prepared a schedule that summarizes RUCO's proposed adjustments to rate base?

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[2] See, e.g., Decision No. 70441 at page 41, Finding of Fact Nos. 16 and 17.

[3] See, e.g., the preceding discussion, including the description of the calculations shown on Schedule A, page 2, at pages 7-8 of this testimony.

A. Yes. As noted above, the adjusted rate base is shown on Schedule B and the adjustments to UNSG's proposed rate base are shown on Schedule B.1. A comparison of the Company's proposed rate base and RUCO's recommended rate base on an Original Cost and Fair Value basis is presented below:

Summary of Rate Base	UNS Gas	RUCO	Difference
Original Cost Rate Base	$ 182,293,106	$ 179,884,439	$ (2,408,667)
RCND Rate Base	$ 329,266,770	$ 325,871,264	$ (3,395,506)
Fair Value Rate Base	$ 255,779,939	$ 252,877,851	$ (2,902,088)

ADJUSTMENTS TO ORIGNAL COST RATE BASE

Q. Please discuss RUCO's adjustments to UNSG's proposed original cost rate base.

A. RUCO has made five adjustments to UNSG's proposed original cost rate base. These have been designated as RUCO Adjustments B-1 through B-6. Each adjustment is discussed below.

B-1 Construction Work in Progress/Post Test Year Plant

Q. Please explain the adjustment shown on Schedule B-1.

A. UNS Gas has proposed to include $1.528 million of Post Test Year Non-Revenue Producing Plant in Service (i.e., Construction Work in Progress ("CWIP")) in rate base. RUCO adjustment B-1 removes that amount of CWIP from rate base.

Q. Please discuss UNS Gas' reason for requesting the inclusion of CWIP in rate base.

A. As described in the testimony of UNS Gas witness Dallas Dukes, the inclusion of post test year non-revenue producing plant in rate base will help the Company begin recovering its investment and an opportunity at earning a reasonable return in a more equitable time frame.

Q. Is inclusion of CWIP in rate base up to the discretion of the Commission?

A. Yes, it is. RUCO's understanding is, in specific instances, the Commission has allowed a utility to include CWIP in rate base, but the Commission's general practice has been to not allow CWIP to be included in rate base. As such, the Commission denied the Company's request for CWIP in rate base in its last rate case.[4]

Q. Does RUCO agree with the proposal of UNS Gas to include CWIP in rate base in the current case?

A. No. In general, RUCO does not favor inclusion of CWIP in rate base unless the utility demonstrates compelling reasons to justify this exceptional ratemaking treatment. For a number of reasons, including the following, RUCO does not support UNS Gas' request for rate base inclusion of CWIP/post test year plant in the current case:

1) Inclusion of CWIP in rate base is an exception to the Commission's normal practice, and UNS Gas has not met its burden of proof showing why it requires such an exceptional ratemaking treatment.

2) The CWIP was not in service at the end of the test year. As of June 30, 2008, the construction projects were not serving customers.

3) The Company has not demonstrated that its June 30, 2008 CWIP balance was for non-revenue producing and non-expense reducing plant. Much of the construction

[4] Decision No. 70011, Docket No. G-04204A-06-0463

appears to be for mains and services which can be related to serving customer growth, and/or can reduce expenses for maintenance.

4) Revenues have not been extended beyond the test year to correspond with customer growth. Hence, including the investment in rate base, without recognizing the incremental revenue it supports, would be imbalanced.

Q. Please elaborate on how including CWIP in rate base is an exceptional ratemaking treatment and why the circumstances in this case do not warrant such treatment.

A. CWIP, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it was not used or useful in delivering gas service to the Company's customers. The ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. The ratemaking process therefore excludes CWIP from rate base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement. In the current UNS Gas rate case, the test year is June 30, 2008, and the construction projects the Company seeks to include in rate base were not providing service during that period. As a general ratemaking principle, such CWIP should be excluded from rate base.

Furthermore, some of the facilities that are being constructed and are included in CWIP will be used subsequent to the test year ended June 30, 2008 to serve additional customers.

It would not be appropriate to include the investment that will serve those new customers without also including the revenues that would be received from those customers. In other words, allowance of CWIP in rate base would result in a mismatch in the ratemaking process.

Additionally, some of the plant being added, such as main replacements, could result in a reduction in maintenance expenditures which would not be reflected in the test year. The inclusion of CWIP in rate base, therefore, creates an imbalance in the relationships between rate base serving customers and the revenues being provided to the utility from customers who were taking service during the test year. Consequently, CWIP should not be allowed in rate base unless there are very compelling circumstances which would warrant an exception to the general rule[5]. In the current case, UNS Gas has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding CWIP from rate base. It is not appropriate to include the CWIP in rate base, particularly as the projects may result in additional revenues or cost savings which have not been reflected in the test year ended June 30, 2008.

Q. How does UNS Gas accrue a return on construction projects?

A. UNS Gas accrues a return, representing its financing costs during the construction period, called Allowance for Funds Used During Construction (AFUDC). This AFUDC return accounts for the utility's financing cost during the construction period. Then, when the

[5] RUCO is aware of only one instance in which the Commission has allowed CWIP in rate base. That occurred in the early 1980s when the Commission considered the costs associated with the Palo Verde Nuclear Plant. Because the up-front costs were so great, the Commission allowed CWIP in rate base in order for the plant to be built.

plant is placed into service, the AFUDC becomes part of the cost of the plant and is depreciated.

Q. How does plant that is placed into service between rate case test years typically get reflected in the regulatory process?

A. If the plant is used to serve new customers, the utility receives revenue from those customers. If the plant helps the utility reduce expenses, such as maintenance, the utility benefits from such cost reductions during the intervening period. Once the plant is recognized in rate base in a test year, and rates are reset, the utility earns a cash return on the plant investment, less accumulated depreciation. The related revenues and expense impacts, including known and measurable expense reductions enabled by the plant, are then also recognized in the ratemaking process.

Q. Did the Commission address this issue in UNS Gas' last rate case?

A. Yes. The Commission's decision in Decision No. 70011 addressed the issue of post-test year plant at pages 7-8, and reached the following conclusion:

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

> rate, and therefore the Company is entitled to inclusion of post-test-year plant if the Commission denies CWIP (Ex. A-27 at 28-29). Even if we were inclined to recognize post-test-year plant in this case, there is not a sufficient basis upon which to evaluate the reasonableness of the request (i.e., whether a mismatch would exist). We therefore deny the Company's proposal on this issue.

Q. Please summarize your adjustment to rate base for CWIP/Post Test Year Plant.

A. As shown on Schedule B-1, UNS Gas' proposed rate base is reduced by $1.528 million to remove the CWIP/ Post Test Year Plant.

Q. Does your adjustment to remove CWIP from rate base affect UNS Gas' expenses?

A. Yes. UNS Gas has proposed to treat CWIP at the end of the test year as if it were plant in service. Consistent with that, UNS Gas has included depreciation and property tax expense associated with CWIP in the test year. Consistent with RUCO's recommendation that CWIP not be included in rate base, RUCO adjustment C-2, which is described in a subsequent section of my testimony, removes the related UNS Gas adjustments for depreciation and property tax expense.

B-2 Customer Advances for Construction

Q. Please explain RUCO Adjustment B-2.

A. This adjustment decreases rate base by $589,152 to reflect the full end-of-test-year balance for Customer Advances.

Q. Why has UNSG sought to remove $589,152 from Customer Advances?

A. Mr. Dukes' direct testimony at page 12 claims that this amount of Customer Advances relates to projects that are not in rate base as of the end of the test year.

Q. Was a similar claim made by UNSG in its last rate case?

A. Yes. As one of UNSG's supporting arguments for its attempt to include CWIP in rate base, UNSG had also attempted to have a portion of Customer Advances excluded from the determination of rate base, using similar arguments from the prior case.

Q. Did the Commission make that UNSG-proposed adjustment in UNSG's last rate case?

A. No. In UNSG's last rate case, the Commission appropriately deducted the full amount of Customer Advances from rate base. This issue is addressed in Decision No. 70011 at pages 8-10, and the Commission reached the following conclusion:

> We agree with Staff and RUCO that advances represent customer-supplied funds that are properly deducted from the Company's rate base. Indeed, the Commission's own rules contemplate that such a deduction is required, as Staff witness Smith testified. Had UNS not requested the inclusion of CWIP in rate base, a ratemaking treatment that is only afforded under extraordinary circumstances (and apparently has not occurred for more than 20 years), there would presumably not have been an issue raised by the Company with respect to an alleged "mismatch" between exclusion of CWIP and deducting advances from rate base. The Company's attempt to frame this issue as one in which it is being treated in a discriminatory manner is unpersuasive.
>
> As we have stated in prior cases, regulated utility companies control the timing of their rate case filings and should not be heard to complain when their chosen test periods do not coincide with the completion of plant that may be considered used and useful and therefore properly included in rate base. We believe our conclusions regarding UNS's CWIP-related proposals are entirely consistent with the treatment that has been afforded to other utility companies regulated by the Commission and provide a result that is fair to both the Company and its customers.

Q. Do you agree with UNSG's claim that some Customer Advances should be excluded in the determination of rate base?

A. No. Because Customer Advances represent non-investor supplied capital, they should be reflected as a deduction to rate base. Additionally, research conducted in the context of

UNSG's last rate case did not reveal any instance in which CWIP for a major utility was excluded from rate base and customer advances were not also reflected as a deduction to rate base. Additionally, the Commission's rules at A.A.C. R14-2-103, Appendix B, Schedule B-1, require companies to reflect Advances as a deduction from rate base.

Q. Please summarize your adjustment to rate base for Customer Advances.

A. The rate base deduction for Customer Advances should reflect the full end-of-test year amount. For the reasons described above, the adjustment proposed by UNSG should be rejected. Customer Advances proposed by UNSG should be increased by $589,152 and rate base reduced by this amount.

B-3 Prepayments

Q. What adjustment has the Company made to rate base for Prepayments?

A. As shown on UNS Gas Schedule B-5, page 2 of 3, the Company has proposed to increase rate base by $95,671 for the use of a 13-month average for Prepayments, rather than using the end-of-test year balance.[6]

Q. Do you agree with that Company-proposed adjustment?

A. No. While the use of an average balance can be appropriate for ratemaking purposes, virtually all of the other rate base balances in this case, including those for Plant in Service, Accumulated Depreciation, Customer Advances, Customer Deposits, etc., are year-end balances. Unless there is a compelling reason to deviate from consistent use of year-end balances, which I do not believe there is for Prepayments, year-end balances should be used for consistency. The Company's proposed adjustment to Prepayments is

[6] UNS Gas also proposes a similar adjustment for Materials and Supplies, but that adjustment is only $728 on a M&S balance of over $2 million and is therefore being ignored on the basis of immateriality.

inconsistent with the majority of the other rate base components, which are based on end-of-test-year balances, is basically unnecessary and should be rejected.

B-4 *Cash Working Capital*

Q. Have you reviewed the Company's request for a cash working capital allowance?

A. Yes. The Company has proposed a cash working capital allowance of approximately $1,568, i.e., under $1,600.

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does UNSG have a positive or negative cash working capital requirement?

A. Based on its calculations, UNSG has a slight positive cash working capital requirement of under $1,600. In other words, ratepayers are essentially supplying the funds used for the day-to-day operations of the Company approximately at the same time UNS Gas is paying for the cash expenditures. On average, revenues from ratepayers are received virtually on the same day as when the utility pays the associated expenditures.

Q. Did UNSG present a lead/lag study in support of its cash working capital requirement?

A. Yes, UNSG performed a lead/lag study to calculate the cash working capital requirement in this case. The Company also provided its lead/lag study calculations with the work papers provided in the case.

Q. Has UNSG made any revisions to the cash working capital calculation included in its filing?

A. No, none of which I am aware.

Q. Are you recommending any revisions to UNSG's cash working capital request?

A. Not at this time. However, in a later filing, such as in surrebuttal, I would propose to update UNSG's cash working capital allowance to reflect the impact of RUCO's adjustments to operating expenses and revenue based taxes, and to synchronize the calculation of cash working capital with RUCO's recommended revenue increase.[7] I have reserved Schedule B-4 for a cash working capital update.

B-5 Customer Deposits

Q. Are you proposing an adjustment for Customer Deposits at this time?

A. No. Customer Deposits, an offset to rate base, also have fluctuated from month to month, as shown in UNSG's response to Staff data request TF 6-28. The test year average for Customer Deposits would be approximately \$3.034 million, versus the June 30, 2008 balance of only \$2.609 million used by UNSG[8]. If Customer Deposits were also to be

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[7] Such synchronization has not yet been reflected at this time, but would be incorporated in RUCO's surrebuttal filing.

[8] The September 2007 amount for customer deposits was missing from UNSG's response to Staff data request TF 6.28(c).

calculated using a test year average, rather than using the year-end balance, an adjustment for this would decrease rate base by approximately $425,000.

I am recommending that a year-end balance be used for Customer Deposits. UNSG's filing reflected the use of a year-end balance. However, if other rate base components, such as Prepayments, are going to be adjusted using a 13-month average, then, for consistency with such an adjustment, Customer Deposits, which have also fluctuated during the test year, should also be reflected in rate base on a 13-month average basis.

B-6 Accumulated Deferred Income Taxes

Q. Please explain the adjustment to Accumulated Deferred Income Taxes ("ADIT") that were included in rate base by UNSG for Accounts 190 and 283.

A. This adjustment is shown on Schedule B-6. The following items reflected in Accounts 190 and 283 are removed:

- Dividend Equivalents
- Restricted Stock
- Restricted Stock - Directors
- Stock Options
- Vacation
- Pension

Each of these items has no corresponding liability that is offsetting rate base. The removal of these items decreases rate base by $423,669. ADIT for a particular item is generally included in rate base as an offset to the related item generating the deferred taxes that is included in rate base, and is excluded if the related item is excluded from rate base. The ADIT components for which there is no corresponding asset or liability should be removed from rate base. Additionally, consistent with my use of the full test-year-end balance of Customer Advances in rate base, I have reversed UNSG's adjustment that had decreased the ADIT balance in Account 190 by $227,413. That reversal increases rate base by the $227,413 of ADIT related to the Customer Advances. The net adjustment to ADIT shown on Schedule B-6 decreases rate base by $196,256.

RECONSTRUCTION COST NEW DEPRECIATED RATE BASE

Q. Please describe RUCO's adjustments to RCND rate base.

A. For the most part, RUCO's adjustments to UNSG's proposed RCND rate base are the same amounts as RUCO's adjustments to OCRB. On its Schedule B-3, page 2, however, UNSG used an amount of $2.514 million for its adjustment for CWIP/post-test year plant, versus the $1.528 million for this adjustment shown on UNSG's Schedule B-2, page 2. Consequently, I have removed the $2.514 million from RCND rate base, as shown on Schedule B.

Q. Do you have any other comments about the significant difference between the OCRB and RCND adjustment amounts used by UNSG for this item?

A. Yes. UNS Gas has not justified how the RCND amount for this item would be so much higher than the OCRB amount. This is essentially for end-of-test year CWIP that UNSG wants to treat as plant in service, so presumably the OCRB and RCND amounts should be the same.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized RUCO's proposed adjustments to operating income.

A. Schedule C summarizes RUCO's recommended net operating income. Schedule C.1 presents RUCO's recommended adjustments to Arizona test year revenues and expenses.

The impact on state and federal income taxes associated with each of the recommended adjustments to operating income are also reflected on Schedule C.1. UNSG's proposed adjusted test year net operating income is $11.600 million, whereas RUCO's recommended adjusted net operating income is $13.091 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1 Revenue Annualization

Q. Please explain RUCO Adjustment C-1.

A. This adjustment reverses the Company's proposed customer annualization adjustment, which had decreased test year revenue by approximately $516,000.

Q. How is a customer annualization typically used in a utility rate case?

A. Where a utility is growing and having to add plant during a test year to serve additional customers, a revenue annualization adjustment is typically employed in order to capture the impact on revenue from customer growth that has occurred and to better match the revenue with the test year plant that has been added to serve the new customers. The revenue growth that relates to the addition of customers is captured in an adjustment to increase revenue that is related to the increased plant that has been added to serve additional customers during the test year.

Q. How has the customer annualization been applied by UNS Gas in the current rate case?

A. While the Company employed an annualization method similar to the one that was used in its last rate case, the rote application of such method in the current case is decreasing test year revenues. Moreover, the decrease in revenue produced by the Company's calculation appears to be related to customer <u>seasonality</u> rather than a permanent decline in customer count during the test year, and therefore should not be adopted because it would understate test year and going-forward revenues.

Q. Hasn't UNS Gas experienced customer growth?

A. Yes, it has. Year after year, UNSG's number of average customers has been increasing. This holds true for the test year as well. Consequently, because customer counts year-over-year have been increasing for the past several years including the test year, test year revenues should not be decreased based on the misapplication of an annualization adjustment. In other words, while the application of an annualization adjustment may have made sense and been appropriate in UNSG's last rate case to account for customer growth that had occurred during that test year which ended December 31, 2005, rote application of such a method in the current case produces results that do not make sense because it essentially assumes that UNSG is losing residential and commercial customers, when clearly that is NOT the case.

Q. What year-over-year increases has UNS Gas experienced for residential customers?

A. The year-over-year increases UNS Gas has experienced for residential customers are summarized in the following table:

Period	Average Number of Residential Customers	Change
2004	118,967	
2005	124,452	5,484
2006	129,054	4,602
2007	131,788	2,734
TYE 6/2008	132,347	559
Avg 7/08 - 3/09	132,601	254

Each year, UNS Gas has gained residential customers. Moreover, even if one looks at comparable periods ending in June 30 through the current test year ended June 30, 2008, UNS Gas has gained residential customers in each year. Information comparing the number of UNS Gas' average residential customers for 12-month periods ending with June 30 is summarized in the following table:

Period	Average Number of Residential Customers	Change
12 Months Ended:		
6/30/2005	121,703	
6/30/2006	126,852	5,149
6/30/2007	130,763	3,911
TYE 6/2008	132,347	1,585

While growth in the test year has slowed compared with the robust growth of previous years, there was still growth of residential customers.

Q. What year-over-year increases has UNS Gas experienced for commercial customers?

A. The year-over-year increases UNS Gas has experienced for commercial customers are summarized in the following table:

Period	Average Number of Commercial Customers	Change
2004	10,654	
2005	10,883	229
2006	11,158	275
2007	11,387	229
TYE 6/2008	11,446	60

Each year, UNS Gas has gained commercial customers. Information comparing the number of UNS Gas' average commercial customers for 12-month periods ending with June 30 is summarized in the following table:

Period	Average Number of Commercial Customers	Change
12 Months Ended:		
6/30/2005	10,764	
6/30/2006	10,989	225
6/30/2007	11,293	304
TYE 6/2008	11,442	149

Looking at comparable periods ending in June 30, through the current test year ended June 30, 2008, UNS Gas has gained commercial customers in each year.

Q. What do you conclude from this information?

A. I conclude that UNS Gas has added, on average, both residential and commercial customers in each and every year, including the test year. Consequently, an adjustment to decrease test year revenue would understate test year and going-forward revenues and be inappropriate and should be rejected. Test year revenue of $516,000 should not be removed as proposed by UNSG. RUCO adjustment C-1 restores this amount of actual test year revenue to the test year.

C-2 Depreciation & Property Taxes for CWIP/Post Test Year Plant

A. This adjustment is related to RUCO Adjustment B-1, which removed UNSG's request for inclusion in rate base of CWIP/Post Test Year Plant. It removes $58,107 of Depreciation Expense, $11,351 of O&M Expense related to depreciation on transportation equipment, and $25,584 of Property Tax Expense related to the adjustment to remove UNSG's request for CWIP/Post Test Year Plant in Service. In total, UNSG's expenses are reduced by $95,042.

Q. How did you determine the recommended assessment rate for property taxes?

A. This adjustment reflects the known statutory assessment ratio of 22 percent applicable for 2009, when rates in this case are expected to be effective. Section 42-15001 of the Arizona State Legislature provides the current percentages for property tax assessments. The assessment rate schedule provides for decreasing the 25 percent rate applicable in 2005 by 0.5 for the year 2006 and 1.0 percent each year thereafter until a 20 percent rate is attained in 2011. The Company's calculation also used a 22 percent assessment rate.

C-3 Incentive Compensation Expense

Q. Please explain Staff Adjustment C-3.

A. This adjustment provides for the allocation of 50 percent of the test year expense for the incentive compensation to shareholders. Test year expense for incentive compensation expense proposed by UNSG is reduced by \$140,484. Related payroll tax expense is decreased by \$12,027.

Q. Please explain why a 50 percent allocation to shareholders is appropriate for an incentive compensation program.

A. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50% of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

Q. Please briefly discuss the key provisions of the incentive compensation program.

A. The Company's response to Staff data request TF 6.64 states UNS Gas non-union employees participate in UniSource Energy Corporation's ("UniSource") Performance Enhancement Plan ("PEP"). The structure of the PEP determines eligibility for certain bonus levels by measuring UniSource's performance in three areas: (1) financial performance; (2) operational cost containment; and (3) core business and customer service goals. Levels of achievement in each area are assigned percentage-based "scores." Those scores are combined to calculate the final payout level. The amount made available for bonuses pursuant to the PEP may range from 15 to 150 percent of the targeted payout level. The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent.

As explained in the Company's response to Staff data request TF 6.64:

> The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 3% to 14% for regular unclassified employees, and 25% to 80% for Managers and Officers. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion, based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Q. Does UNSG recognize that its proposed treatment of incentive compensation expense in the current case represents a conscious deviation from principles and policies established in prior Commission Orders?

A. Yes. Data request TF 6.103 asked[9]:

> Are there any aspects of the Company's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and

[9] See Attachment RCS-5.

> policies established in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission orders, how the Company's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

UNSG's response to this data request states in part that: "In the prior Commission decision, 50% of the incentive compensation expense was excluded from revenue requirements. UNS Gas is requesting full recovery of the normal and recurring level of incentive compensation expense."

Q. What reasoning does UNSG give for its request to recover 100% of its incentive compensation expense despite prior Commission Orders?

A. In his Direct Testimony at page 21, Company witness Dukes stated that the Company's incentive compensation program is designed to award non-union employees for their contributions to the company.

Q. What criteria has the Commission found important in deciding issues concerning utility incentive compensation in recent cases?

A. The criteria the Commission has found important in deciding this issue in recent cases are described in various orders which have addressed the treatment of utility incentive compensation expense for ratemaking purposes. In Decision No. 68487 (February 23, 2006), the Commission adopted Staff's recommendation for an equal sharing of costs associated with the Southwest Gas Corporation's ("SWG") Management Incentive Plan ("MIP") expense. For example, in reaching its conclusion regarding SWG's MIP, the Commission stated in part on page 18 of Order 68487 that:

> We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the

> benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendations to be a reasonable resolution.

Mr. Dukes has not refuted the fact that both shareholders and ratepayers derive some benefit from incentive goals.

Q. Do UNSG's shareholders and customers both benefit from the achievement of incentive compensation program?

A. Yes. Shareholders benefit from the achievement of financial goals. Additionally, shareholders benefit from the achievement of expense reduction and expense containment goals between rate cases. Shareholders and ratepayers can both benefit from the achievement of customer service goals.

Q. How does the amount of UNSG's incentive compensation expense in the current case compare with the amount from UNSG's prior rate case?

A. The following table summarizes UNSG's incentive compensation (PEP) expense in the current case, the prior case (Docket No. G-04204A-06-0463), and the amount which was ultimately allowed in Decision 70011:

Line No.	Description	Amount	Source
1	Incentive compensation (PEP) included in current case	$ 280,968	Schedule C-3
2	Incentive compensation (PEP) expense requested in Docket No. G-04204A-06-0463	$ 126,859	Staff Witness Smith, Sch. C-6
3	Increase	$ 154,109	L1 - L2
4	Percent Increase	121.48%	L3/L2
5	Amount Allowed in Decision No. 70011	$ 63,430	Decision 70011

As shown in the above table, the Company's incentive compensation expense is significantly higher in the current rate case than it was in the prior UNSG rate case.

Q. Have the facts changed materially since the last UNS Gas rate case that a different result concerning the sharing of incentive compensation expense should occur?

A. No, I don't believe so. The rationale for the 50 percent allocation to shareholders of this expense in the current case appears to be consistent with the Commission's findings concerning SWG's MIP in Decision No. 68487, and findings about UNSG's incentive compensation expense in Decision No. 70011. In Decision No. 70011 (November 27, 2007), in the last UNS Gas rate case, Docket No. G-04204-06-0463 et al, the Commission stated in part on page 27 that:

> We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.

Q. Did UNSG appeal Decision No. 70011?

A. No.

Q. Was an equal sharing of incentive compensation expense ordered in other recent Commission decisions in rate cases involving Arizona utilities?

A. Yes. In Decision No. 70360 (May 27, 2008), in the recent UNS Electric, Inc. rate case, Docket No. E-04204A-06-0783, the Commission stated at page 21 that:

> Consistent with our finding in the UNS Gas rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program...Given that the arguments raised in the UNS Gas case are virtually identical to those presented in this case, we see no reason to deviate from that recent decision.

Finally, in Decision No. 70665 (December 24, 2008), in the most recent Southwest Gas Company rate case, Docket No. G-01551A-07-0504, the Commission stated at page 16 that:

> In the last Southwest Gas rate case, as well as several subsequent cases,[3] we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated:
>
>> In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.
>
> (Id.) We believe the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs.[4]

[3]See UNS Gas, Inc., Decision No. 70011 (November 27, 2007) at 27; Arizona Public Service Co., Decision No. 69663 (June 28, 2007) at 27; and UNS Electric, Inc., Decision No. 70360 (May 27, 2008) at 21.
[4]On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ("SIP"). The costs related to similar incentive plans were recently rejected for APS and UNS Electric. (See Ex. S-12 at 32-34.) As was noted in the APS case, stock performance incentive goals have the potential to negatively affect customer service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price. (Decision No. 69663 at 36.)

Q. Should the 50/50 ratepayer/shareholder sharing that the Commission applied to utility incentive compensation in UNSG's last rate case be modified to a 100 percent ratepayer responsibility for such cost based on the analysis presented by Mr. Dukes?

A. No. The 50/50 sharing of UNSG's incentive compensation program cost ordered by the Commission in Decision No. 70011 should continue to apply in the current UNSG rate case.

Q. Please summarize your recommendation concerning UNSG's incentive compensation expense.

A. I recommend continuing the 50 percent allocation for UNSG's incentive compensation expense to shareholders ordered by the Commission in Decision No. 70011. This results in a reduction to test year expense of $140,484.

C-4 Stock-Based Compensation Expense

Q. What amounts of stock-based compensation expense has UNSG included in the test year?

A. UNSG's response to data request RUCO 1.46 identifies $266,399 of stock-based compensation expense in the test year.

Q. For what types of stock-based compensation has UNSG included an expense in the test year?

A. UNSG has included an expense in the test year for the following types of stock-based compensation:

- Stock Option Expense
- Dividend Equivalents on Stock Units
- Performance Stock Award
- Dividend Equivalent on Stock Options
- Directors Stock Awards

As described in the Company's response to TF 6.92 and UniSource Energy's March 22, 2009 Proxy Report, the UNSG's parent company, UniSource Energy offers the following types of stock-based compensation:

Stock options

Stock options are offered as part of as part of UniSource Energy's long-term incentive program for officers. Options have an exercise price equal to the fair market value on the date of grant and a maximum term of ten years. The options vest at one-third increments beginning on the first anniversary of grant date.[10]

Performance share awards

Performance share awards reward achievement of financial performance objectives and/or shareholder value objectives. Performance share awards are paid in shares of UniSource Energy stock under a three year cycle. Performance goals are based on compound annual shareholder return. No dividends are paid on performance shares until earned and vested.

[10] Also see, e.g., UNSG's responses to Staff data request TF 6.92.

Directors stock awards

Non-employee directors receive an annual award in restricted stock units as follows:

- Directors serving on the date of the Annual Shareholders' meeting receive a grant on the date of that meeting. Any person who first becomes a director after the Annual Shareholders' meeting receives a grant on a date approved by the Compensation Committee. All restricted stock unit grants to directors vest at the earlier of the next annual meeting following grant date or the first anniversary of grant.
- The actual number of restricted stock units granted is calculated by dividing $45,000 by the closing price of our common stock on the date of grant.
- Vested stock unit grants must be deferred and distributed in January of the year following the year during which a director ceases to serve as a member of our Board. Deferred stock units accrue dividend equivalents during the deferral period. Deferral stock units are distributed in shares of Company stock.

Dividend equivalent on stock units and stock options

Under the Director's Deferred Compensation Plan ("DCP"), certain eligible officers and other employees selected for participation, and non-employee members of the Board, may elect to defer a percentage of the compensation of fees that would otherwise become payable to the individual for his services. Each participant in the DCP may elect that his deferrals be credited in the form of additional deferred shares instead of cash. Deferred shares accrue dividend equivalents, credited in the form of additional deferred shares, as dividends are paid by UniSource Energy on its issued and outstanding common stock. Each participant elects the time and manner of payment (lump sum or installments) of his deferred shares under the DCP.

Q. Did the Commission recently disallow another utility's stock based compensation in a recent decision?

A. Yes. In Decision No. 69663, from a recent APS rate case, the Commission adopted a Staff recommendation in that case where cash-based incentive compensation expense was allowed and stock-based compensation was disallowed. Additionally, page 36 of Decision No. 69663 indicates that the Commission rejected an argument by APS that the Commission not look at how compensation is determined or its individual components:

> "APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost."
>
> "We agree with Staff that APS' stock-based incentive compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate. As testified to by Staff witness Dittmer and set out in Staff's Initial brief, "[e]nhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. ... For example, some maintenance can be temporarily deferred, thereby boosting earnings. ... But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." [cite omitted] To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation."

Thus, in Decision No. 69663, the Commission made an adjustment to disallow a portion of that utility's incentive compensation expense, specifically the stock-based compensation.

Q. Was stock-based compensation expense also disallowed in the Commission's recent decision in the rate case involving UNS Electric, Inc.?

A. Yes, it was. In Decision No. 70360 at page 22, the Commission, in referencing a similar decision regarding Southwest Gas Corporation as well as APS' last rate case stated:

> "For these same reasons, we agree with Staff that test year expenses should be reduced to remove stock-based compensation to officers and employees...The disallowance of stock-based compensation is consistent with the most recent rate case for Arizona Public Service Company (Decision No. 69663)."

Q. Please discuss the reasons for removing stock-based compensation.

A. Ratepayers should not be required to pay executive compensation that is based on the performance of the Company's (or its parent company's) stock price. Additionally, prior to being required to expense stock options for financial reporting purposes under Statement of Financial Accounting Standards No. 123 Revised (SFAS 123R), the cost of stock options was typically treated as a dilution of shareholders' investments, i.e., it was a cost borne by shareholders. While SFAS 123R now requires stock option cost to be expensed on a company's financial statements, this does not provide a reason for shifting the cost responsibility for stock options from shareholders to utility ratepayers.

Q. Please explain RUCO Adjustment C-4.

A. As shown on Schedule C-4, this adjustment decreases test year expense by $266,399 to reflect the removal of UNSG's stock option compensation expense that is allocated to Arizona operations. The expense of providing stock options and other stock-based compensation to officers, employees and directors beyond their other compensation should be borne by shareholders and not by ratepayers.

C-5 Supplemental Executive Retirement Plan Expense

Q. Please explain RUCO Adjustment C-5.

A. This adjustment removes 100% of the expense for the Supplemental Executive Retirement Plan ("SERP"). The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. Has utility SERP expense been disallowed by the Commission in a series of recent rate cases?

A. Yes. In Decision No. 68487, February 23, 2006, in a Southwest Gas Corporation rate case, the Commission adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Order 68487 that:

> Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations

applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

Q. Was SERP expense disallowed in the Commission's decision in the last rate case involving UNS Gas, Inc?

A. Yes, it was. See Decision No. 70011 at pages 27-29. Notably, at page 28 of that Decision, the Commission stated:

> … the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case [See also Arizona Public Service Co., Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were excluded in their entirety.], and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

Q. Was SERP expense also disallowed in the Commission's recent decisions in the rate cases involving UNS Electric, Inc.?

A. Yes, it was. In the recent UNS Electric, Inc. rate case, in Decision No. 70360 at page 22, referencing the above captioned quote, the Commission stated:

> *We see no reason to depart from the rationale on this issue in the most recent UNS Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.*

The Commission's Decision No. 70665 (December 24, 2008) in the most recent Southwest Gas rate case, Docket No. G-01551A-07-0504, stated as follows on pages 17-18:

> We agree with Staff and RUCO that the SERP expenses sought by Southwest Gas should once again be disallowed. We do not believe any

material factual difference exists in this case that would require a result that differs from the Company's prior case. In that case, we stated:

> [W]e believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

(Decision No. 68487 at 19.)

In the recent UNS Gas, APS, and UNS Electric cases, we followed the rationale cited above in disallowing SERP expenses. In Decision No. 70011, we indicated that SERP costs should not be recoverable and indicated:

> [T]he issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

[Id. At 28, (footnote omitted).] For these reasons, we agree with the recommendations of Staff and RUCO that the request for inclusion in rates of SERP expenses should be denied. We therefore adopt the recommendations of Staff and RUCO on this issue.

Q. What adjustment related to UNSG's SERP expense do you recommend?

A. I recommend the adjustment to remove UNSG's expense for the SERP, which is shown on Schedule C-5 and reduces O&M expense by $101,021.

C-6 American Gas Association Dues

Q. Please explain RUCO's proposed adjustment for American Gas Association dues.

A. This adjustment is shown on Schedule C-6 and reduces test year expense by $18,678 to reflect the removal of 40 percent of AGA dues.

Q. How does RUCO's proposed adjustment for AGA dues compare with UNSG's proposed treatment of such dues?

A. As noted above, I recommend the removal of 40 percent of AGA core dues, while UNSG's filing reflected the removal of only 4 percent of the AGA dues.

Q. What information did UNS Gas provide concerning the specific benefits of AGA activities to the Company and Arizona ratepayers?

A. UNSG witness Gary A. Smith addresses AGA benefits at pages 9-14 of his direct testimony. The AGA does provide some benefit to the utilities that comprise its membership; however, this does not negate the fact that a significant portion of AGA expenditures are related to programs which should be disallowed for ratemaking purposes. I have attached to my testimony a listing and description of the AGA's functions as listed in the March 2005 Annual Audit report to the National Association of Regulatory Utility Commissioners (NARUC), and have identified the percentage of AGA activities related to each function.

Q. Does the information provided by UNSG show that 96 percent (100 percent minus the Company's 4 percent disallowance) of AGA dues-funded activities are beneficial to the Company and/or to its Arizona ratepayers?

A. No. UNS Gas has demonstrated that there is some benefit of AGA membership to the Company and to Arizona ratepayers from some of the AGA's functions. However, the Company has failed to demonstrate that ratepayers should fund activities conducted through an industry organization that would be subject to disallowance if conducted directly by the utility. The Company has failed to demonstrate that a disallowance of AGA dues of only 4 percent is adequate. As I will discuss below, other states have used a significantly higher disallowance percentage for gas utility AGA dues than UNSG is proposing here.

Q. To your knowledge what percentage disallowance for utility AGA dues has been used in other recent utility rate cases?

A. In the last UNS Gas rate case, as described on pages 32-33 of Decision No. 70011, UNS Gas had initially included $41,854 for AGA dues, and RUCO witness Moore recommended a partial disallowance of $1,523, based on an AGA/NARUC Oversight Committee Report indicating that 1.54 percent of AGA dues were for marketing and 2.10 percent of dues were for lobbying activities. UNS Gas agreed with that adjustment, and it was ultimately adopted by the Commission. At pages 33-34 of Decision No. 70011, however, the Commission also stated that:

> Mr. Smith raises a valid point regarding the nature of AGA dues and whether a higher percentage of such dues should be disallowed as related to activities that are not necessary for the provision of services to UNS customers. However, we believe it is reasonable, in this case, to allow $40,311 ($41,854 - $1,523), in accordance with RUCO's recommendation. As we indicated in the Southwest Gas Order, however, we expect UNS in its next rate case to provide more detailed support for the allowance of AGA dues and how the AGA's activities benefit the Company's customers aside from marketing and lobbying efforts.

Since my testimony in the last UNS Gas rate case, I have become aware of AGA dues disallowances made in gas utility rate cases in Michigan and California. In California, it appears that a disallowance of 25 percent of Pacific Gas and Electric Company's AGA dues was made by the Company itself in its filing in Application 05-12-002 (filed 12/2/05) as related to lobbying in the broader sense. In a more recent California rate case, Application No. 06-12-009, involving San Diego Gas and Electric, that utility appears to have proposed a 2 percent AGA dues disallowance for lobbying in the narrowest sense; the Division of Ratepayer Advocates ("DRA") proposed that the entire cost of SDG&E's AGA dues be excluded; and UCAN supported either the full disallowance or a 25 percent disallowance based on the result from the PG&E rate case and their review of AGA activities information.[11]

In a Michigan case involving Consumers Energy Company's gas utility operations[12], that utility conceded to a PSC Staff adjustment to disallow 16.17 percent of the AGA dues. As described in the testimony of MPSC Staff witness Wanda Clavon Jones[13]:

> Staff adjusted dues to eliminate activities that would not be allowed if the Company took on those activities for themselves. These activities include Public Affairs (15.43%) and Media Communication-Promotion (0.74%). Staff obtained the information necessary to make this adjustment from the Audit Report on Expenditures of the American Gas Association issued June 2001. The total disallowance is 16.17%, or $60,780. This disallowance is consistent with the last rate cases of Consumers, MichCon and MGU.

Q. How did you determine the percent disallowance for AGA dues?

A. This was based upon a review of information in the two most recent National Association of Utility Regulatory Commissioners (NARUC) sponsored Audit Reports of the

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[11] A final order has apparently not been issued yet in the SDG&E rate case, and the parties are apparently working on a settlement.

[12] Michigan PSC Case No. U-13000.

[13] Filed 12/14/2001, at page 6

Expenditures of the American Gas Association, as well as the components by function of the AGA's 2007 and 2008 budgets. I also relied upon a Florida PSC Staff memorandum, discussed in more detail below, which contained a 40 percent AGA dues disallowance. Copies of relevant pages from the NARUC-sponsored audit reports are provided in Attachment RCS-4. AGA 2007 and 2008 budget information, by component, is summarized on Schedule C-6, page 2.

Q. What is the purpose of the NARUC-sponsored audits of AGA expenditures?

A. The purpose of the NARUC-sponsored audits of AGA expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. As stated in the June 2001 memo to the Chairs and Chief Accountants of the State Regulatory Commissions included with the NARUC-sponsored audit of 1999 AGA expenditures: "Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities." The NARUC-sponsored audit categorizes the AGA expenditures and, as stated in the aforementioned memo, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit."

Q. Have other regulatory commissions required similar adjustments to utility-incurred AGA dues, based on the results of the NARUC-sponsored audits?

A. Yes. As an example, I have included in Attachment RCS-4, an excerpt from a Florida Public Service Commission Staff Memorandum (dated 12/23/03) in a City Gas Company rate case addressing this issue. As stated in that document:

In City Gas's last rate case, *In re: Request for rate increase by City Gas Company of Florida*, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. *In re: Application for a rate increase by City Gas Company of Florida*, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

Q. Did the Commission also address the issue of the appropriate portion of AGA dues to disallow for ratemaking purposes in the most recent Southwest Gas Corporation rate case?

A. Yes, it did. The Commission adopted a 40 percent disallowance of AGA dues in Decision No. 70665, in the recent Southwest Gas rate case. In Docket No. G-01551A-07-0504, the Commission adopted Staff's recommendation to disallow 40% of AGA dues. Decision No. 70665, at page 12 stated that:

> We find that Staff's recommended disallowance of 40 percent of AGA dues represents a reasonable approximation of the amount for which ratepayers receive no supportable benefit.

Q. What amount of AGA membership dues expense have you removed from test year expense?

A. As shown on Schedule C-6, I have removed 40 percent, or $18,678, from the $46,694 of test year expense for AGA membership dues. This removes $16,762 more than UNSG's proposed 4 percent removal which amounted to $1,915.

C-7 Outside Legal Expense

Q. Please explain RUCO's adjustment to Outside Legal Expense.

A. This adjustment removes a portion of UNS Gas' significant *pro forma* increase amount for normalizing outside legal expense in the test year.

Q. What is the test year amount of Outside Legal Expense?

A. The Company's test year expense for Outside Legal Expense (other than rate cases) is $83,555. The Company has made a *pro forma* adjustment to increase Outside Legal

Expense by $305,984 to normalize this expense in the test year, based on a three year average of 2005 - 2007 expenses, which included large annual legal costs related to an El Paso Natural Gas ("EPNG") pipeline case before the FERC.

Q. Describe UNS Gas' historical Outside Legal Expenses.

A. The Company spent $488,000, $439,000, and $242,000 in the years 2005, 2006, and 2007 on outside legal costs for matters other than ACC rate cases. A significant amount of these fees in those years are related to the EPNG regulatory proceedings before the FERC, which had settled. The Company's outside legal fees have steadily declined since its last rate case. The Company also stated in its UES Results of Operations for Year End 2008 :

Begin Confidential

[14] ***End Confidential***

Q. What amount of outside legal expense are you recommending?

A. I am recommending that a normalized amount of outside legal expense excluding the EPNG legal costs be used. Because it appears that some level of EPNG FERC costs will be ongoing, I have provided for an annual amount for EPNG FERC proceedings of approximately $100,000 based on actual test year costs. As shown on Schedule C-7, RUCO has reduced outside legal expense by $217,674.

C-8 Fleet Fuel Expense

Q. Please explain adjustment C-8.

[14] TF-6.46 UNSG(0571)07991

A. This adjustment reduces the Company's fleet fuel expense included in the test year. The test year fleet fuel expense is based on unusually high fuel prices in effect during the test year, in some months over $4.00 a gallon, the Country's record high point. The amount of gallons purchased in the test year is the highest among historical yearly gallons purchased. Schedule C-8 shows a historical comparison of gallons purchased by year. If one calculates a monthly average of gallons for 2009 and annualizes it for the rest of the 2009, the annual amount of gallons yields an amount lower than the three year average. The Company's response to RUCO data request 1.94 states the current price of gas as of May 6, 2009 is $2.09 per gallon. According to ArizonaGasPrices.com , the current price of gas in Arizona is $2.278 per gallon as of May 29, 2009, but has recently been trending higher. My adjustment to fleet fuel expense calculates fleet fuel expense based a three year average of gallons purchased multiplied by an the current price of gas as of May 29, 2009 of $2.278 per gallon. As shown on Schedule C-8, I have reduced fleet fuel expense by $240,913. This adjustment will be updated if gas prices change significantly during the course of this proceeding.

C-9 Rate Case Expense

Q. What amount of rate case expense is the Company requesting recovery for in this case?

A. UNS Gas is requesting recovery of $500,000 for current rate case expenses over three years for an annual allowance of $166,667 per year. The Company also included $100,000 of unamortized rate case expense from the prior rate case and proposed that also be normalized over three years for an additional amount of $33,333, bringing the Company's request for *pro forma* total rate case expense to $200,000 per year. The

Company stated in response to Staff data request TF 6.68 that it did not remove amortization of rate case expense related to the previous rate case that will be recovered prior to new rates becoming effective and therefore, the Company's test year amount of rate case expense included an additional $58,333. The response to TF 6.68 also states that this amount would be removed resulting in a reduction of test year rate case expense of $58,333.

Q. Do you agree with the Company's proposed amount of rate case expense for this case?

A. No. Even with the Company's proposed correction, the total amount of rate case expense is excessive and would represent an unreasonable burden on ratepayers. Additionally, the amount included in rates for an allowance for rate case expense should be understood to be a normalized amount, not an amortization.

Q. What total amount of rate case expense was allowed in the last UNSG rate case?

A. The allowance for rate case expense was based on a total amount of $300,000 for rate case expenses in its prior rate case, Docket No. G-04204A-06-0463, normalized over a period of three years.

Q. How does the current UNSG rate case compare with the last UNSG rate case?

A. The current UNS Gas rate case is similar to and presents many of the same issues and adjustments to rate base and operating expenses (i.e., CWIP, property taxes, incentive compensation, etc.), if not less, than those that were addressed by the

Commission in the Company's last rate case. For example, in the prior rate case, it was the Company's first case under its new ownership. The Company also conducted a depreciation study supporting new depreciation rates in the prior case. UNS Gas is not proposing to revise its depreciation rates in this case.

Q. What do you recommend for the allowance for rate case expense for UNS Gas in this proceeding?

A. I recommend an annual allowance of $100,000, based on normalizing a total amount of $300,000 over a three-year period. The $500,000 for current rate case cost requested by UNS Gas is nearly double (i.e., is almost 81 percent higher) the amount of rate case expense requested and allowed by the Commission in the Southwest Gas' last rate case, Docket No. G-01551A-07-0504, which was $276,000 in total and was normalized over a three-year period, to produce an annual allowance of $92,000 per year. The rate case expense allowance in the last UNS Gas case was $100,000, based on normalizing a total amount of $300,000 over three years. Additionally, the rate case allowance in the last UNS Electric rate case was $100,000, based on normalizing a total amount of $300,000 over three years. The current UNS Gas rate case has similarities to the last UNS Gas and UNS Electric rate cases in terms of both the scope of issues in the cases, and the majority of each application being sponsored by in-house or affiliated company staff.

Q. Please summarize your recommended adjustment.

A. I recommend an annual allowance of $100,000 per year, based on a total of $300,000 normalized over three years. Schedule C-9 reduces the Company's proposed annual allowance for current rate case costs by $100,000.

I also recommend that the amount recorded by UNS Gas in the test year of $58,333 for prior rate case expense be removed. The Company's response to Staff data request TF 6.68 indicates this adjustment is needed to correct an error in UNS Gas' filing.

As shown on Schedule C-9, my total adjustment allows for a $100,000 per year normalized rate case expense, and reduces the rate case expense in UNSG's filing by $158,333.

C-10 Interest Synchronization

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, my proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule C-10. This adjustment increases income tax expense by $30,215 - the amount shown on Schedule C-10 and decreases the Company' achieved operating income by a similar amount.

C-11 Property Tax Expense

Q. Please explain RUCO Adjustment C-11.

A. This adjustment reflects the most current average known property tax rate for the 2008 tax year.

Q. How did you determine the most current average known property tax rate for the 2008 tax year?

A. The Company's response to RUCO 1.90 indicates the most current average known property tax rate for the 2008 tax year is 7.6127 percent as opposed to the 8.1359 percent used by the Company in calculating test year property tax expense.

Q. How did you determine the recommended assessment rate?

A. As previously stated, Section 42-15001 of the Arizona State Legislature provides the current percentages for assessed valuation of class one property for the years 2005 through 2010. The new assessment rate schedule provides for decreasing the 25 percent rate applicable in 2005 by 0.5 for the year 2006 and 1.0 percent each year thereafter until a 20 percent rate is attained in 2011.

The assessment rate for 2008 was 23 percent. The Company's calculation used the 22 percent assessment rate for 2009. Since the Commission approved rates are expected to become effective no later December 1, 2009, and the Company's anticipated rate case interval is three years, as evidenced by the Company's and RUCO's proposed normalization period for rate case expense, the property tax rate that will be effect for 2009 should be used. In terms of determining the recommended assessment rate, I also considered how my recommendation in the current UNS Gas rate case compares with property tax rates approved in recent Arizona gas rate cases. This comparison is summarized in the following table:

Utility:	UNS Gas, Inc	Southwest Gas Corp.	UNS Gas, Inc	Southwest Gas Corp.
Docket:	G-04204A-08-0571	G-01551A-07-0504	G-04204A-06-0463	G-01551A-04-0876
Test Year Ended:	6/30/2008	4/30/2007	12/31/2005	8/31/2004
New Rates Effective:	12/1/2009	12/1/2008	mid-2007	Order issued 2/23/06
Estimated Filing Interval:	3 years	3 years	3 years	3 to 4 years
Assessment Rate Used:	22 percent	23 percent	24 percent	24.5 percent
Corresponding Effective Year	2009	2008	2007	2006

In the 2004 SWG rate case, it appears that the utility, Staff and RUCO all ultimately agreed on the appropriateness of using a 24.5 percent assessment rate effective for 2006 in conjunction with the test year in that case ending August 31, 2004. In the last UNS Gas rate case an assessment rate of 24 percent for 2007 was used for rates that became effective in mid-2007. In the most recent Southwest Gas rate case, an assessment rate of 23 percent was used effective for 2008 for rates that became effective on December 1, 2008. I believe the appropriateness of using the known 22 percent assessment rate for 2009 in the current UNS Gas rate case is supported by the comparison in the above table.

Q. What is RUCO's recommended property tax expense adjustment?

A. As shown on Schedule C-11, Staff's recommended adjustment reduces UNS Gas' proposed property tax expense by $230,913.

C-12 2010 Pay Increase

Q. Please explain your adjustment for a 2010 pay increase.

A. This adjustment is shown on Schedule C-12, and reduces UNSG's proposed expense for payroll by $225,740 and related payroll tax expense by $24,882 to remove a projected 2010 pay increase. The Company increased its end-of-test-year payroll for two rounds of pay increases: a 3 percent increase in 2009 and another 3 percent increase projected for 2010. The 2010 pay increase is not known and measurable, and is too far removed from the test year. Additionally, with the poor economy many companies are curtailing budgeted pay increases. For all of these reasons, the 2010 pay increase projected by UNS Gas should be removed from test year expense.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

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, 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 on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)

82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company – Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)

851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities
T E-1032-88-102	Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)

R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)

PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)

Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016,	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
Phase I	
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)

Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. 01-05-19 REO3	Yankee Gas Service (CT DPUC)
Docket No. G-01551A-00-0309	Southwest Gas Corporation (Arizona Corporation Commission)
Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
E-01345A-06-009	Arizona Public Service Company (Arizona CC)
05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power Co. (West Virginia PSC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)

G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)

Attachment RCS-2

RUCO Accounting Schedules

Accompanying the Direct Testimony of Ralph C. Smith

UNS Gas Confidential Information Has Been Redacted

Schedule	Description	Pages	Note
	Revenue Requirement Summary Schedules		
A	Calculation of Revenue Deficiency (Sufficiency)	2	
A-1	Gross Revenue Conversion Factor	1	
B	Adjusted Rate Base	1	
B.1	Summary of Adjustments to Rate Base	1	
C	Adjusted Net Operating Income	1	
C.1	Summary of Net Operating Income Adjustments	2	
D	Capital Structure and Cost Rates	2	
	Rate Base Adjustments		
B-1	Construction Work in Progress/Post Test Year Plant	1	
B-2	Customer Advances	1	
B-3	Prepayments	1	
B-4	Cash Working Capital		[A]
B-5	Customer Deposits		[A]
B-5	Accumulated Deferred Income Taxes	1	
	Net Operating Income Adjustments		
C-1	Gas Retail Revenue	1	
C-2	Depreciation & Property Taxes for CWIP	2	
C-3	Incentive Compensation	1	
C-4	Stock-Based Compensation Expense	1	[B]
C-5	Supplemental Executive Retirement Plan Expense	1	
C-6	American Gas Association Dues	2	
C-7	Outside Services Legal Expense	1	
C-8	Fleet Fuel Expense	1	
C-8.1	Fleet Fuel Usage	1	
C-9	Rate Case Expense	1	
C-10	Interest Synchronization	1	
C-11	Property Tax Expense	1	
C-12	2010 Pay Increase	2	
	Total Pages (including Contents page)	31	

[A] Placeholder, schedule reserved for adjustment to be calculated at a later stage of proceeding, if necessary

[B] Contains Company-designated CONFIDENTIAL INFORMATION

UNS Gas Inc.
Computation of Increase in Gross Revenue Requirement

Test Year Ended June 30, 2008

			UNS Proposed		RUCO Proposed	
Line No.	Description	Reference	Original Cost (A)	Fair Value (B)	Original Cost (C)	Fair Value (D)
1	Adjusted Rate Base	Sch. B	$ 182,293,106	$ 255,779,939	$ 179,884,439	$ 252,877,851
2	Rate of Return	Sch D	9.54%	6.80%	7.55%	5.38%
3	Operating Income Required		$ 17,390,762	$ 17,390,762	$ 13,581,275	$ 13,604,828
4	Net Operating Income Available	Sch. C	$ 11,600,004	$ 11,600,004	$ 13,090,781	$ 13,090,781
5	Operating Income Excess/Deficiency		$ 5,790,758	$ 5,790,758	$ 490,494	$ 514,047
6	Gross Revenue Conversion Factor	Sch. A-1	1.6366	1.6366	1.636582	1.636582
7	Overall Revenue Requirement		$ 9,477,048	$ 9,477,048	$ 803,000	$ 841,000
8	Difference between OCRB and FVRB calculations			$ -		$ 38,000

Notes and Source
Cols. A & B taken from UNS Gas, Inc. filing, Schedule A-1

8	Gas Retail Revenue	Sch. C	$ 51,157,763	$ 51,157,763	$ 51,673,766	$ 51,673,766
9	Percentage Increase		18.53%	18.53%	1.55%	1.63%

See page 2 for additional Fair Value calculations RUCO is presenting for the Commission's consideration.
RUCO's amounts on line 7 are rounded to the nearest thousand.

UNS Gas Inc.
Computation of Increase in Gross Revenue Requirement

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule A

Line No.	Description	Reference	Fair Value Calculation 1 (A)	Fair Value Calculation 2 (B)	Fair Value Calculation 3 (C)	Fair Value Calculation 4 (D)	RUCO Recommended (E)
1	Adjusted Rate Base	Sch. B	$ 252,877,851	$ 252,877,851	$ 252,877,851	$ 252,877,851	$ 252,877,851
2	Rate of Return	Sch D	6.30%	5.05%	5.37%	5.73%	5.38% [a]
3	Operating Income Required		$ 15,931,305	$ 12,770,331	$ 13,579,541	$ 14,489,901	$ 13,604,828
4	Net Operating Income Available	Sch. C	$ 13,090,781	$ 13,090,781	$ 13,090,781	$ 13,090,781	$ 13,090,781
5	Operating Income Excess/Deficiency		$ 2,840,524	$ (320,450)	$ 488,760	$ 1,399,120	$ 514,047
6	Gross Revenue Conversion Factor	Sch. A-1	1.636582	1.636582	1.636582	1.636582	1.636582
7	Overall Revenue Requirement		$ 4,649,000	$ (524,000)	$ 800,000	$ 2,290,000	$ 841,000 [b]
		Evaluation:	way too high	too low	too low	too high	recommendation

Notes and Source

Line No.	Description	Reference	(A)	(B)	(C)	(D)	(E)
8	Gas Retail Revenue	Sch. C	$ 51,673,766	$ 51,673,766	$ 51,673,766	$ 51,673,766	$ 51,673,766
9	Percentage Increase		9.00%	-1.01%	1.55%	4.43%	1.63%

RUCO's amounts on line 7 are rounded to the nearest thousand.
Explanation of Fair Value Calcualtions (See Schedule D, page 2, for details):
Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation
Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation
Calculation 3 - With Fair Value Rate Base Increment at Zero Cost
Calculation 4 - With Fair Value Rate Base Increment at 1.25 Percent

[a] Recommended FVROR selected based on informed judgment after reviewing OCRB and FVRB calculations
[b] See page 1 of this schedule for how this recommendation compares with an OCRB-based calculation

UNS Gas, Inc.
Computation of Gross Revenue Conversion Factor

Test Year Ended June 30, 2008

Line No.	Description	Company Proposed (A)	RUCO Proposed (B)
1	Gross Revenue	100.00%	100.00000%
2	Less: Uncollectible Revenue	0.487000%	0.48700%
3	Taxable Income as a Percent	99.51%	99.51300%
4	Less: Federal and State Income Taxes	38.41%	38.41003%
5	Change in Net Operating Income	61.10%	61.10297%
6	Gross Revenue Conversion Factor	1.6366	1.636582

Notes and Source

Col.A: UNS Gas Inc. Filing, Schedule C-3

7	Combined Income Tax Rate		38.5980%

UNS Gas, Inc.
Original Cost and RCND Adjusted Rate Base

Test Year Ended June 30, 2008

Line No.	Description	Original Cost: As Adjusted by UNS (A)	Original Cost: RUCO Adjustments (B)	Original Cost: As Adjusted by RUCO (C)	RCND: As Adjusted by UNS (D)	RCND: RUCO Adjustments (E)	RCND: As Adjusted by RUCO (F)
1	Gross Utility Plant in Service	$ 318,227,624	$ (1,527,588)	$ 316,700,036	$ 561,025,858	$ (2,514,427)	$ 558,511,431
2	Less: Accumulated Depreciation	$ (87,543,544)	$ -	$ (87,543,544)	$ (152,278,962)	$ -	$ (152,278,962)
3	Net Utility Plant in Service	$ 230,684,080	$ (1,527,588)	$ 229,156,492	$ 408,746,896	$ (2,514,427)	$ 406,232,469
4	Southern Union Acquisition Premium	$ -	$ -	$ -	$ -	$ -	$ -
5	Less: Accum. Amort. - So. Union Acq. Premium	$ -	$ -	$ -	$ (3,553)	$ -	$ (3,553)
6	Net Southern Union Acquisition Premium	$ -		$ -	$ (3,553)	$ -	$ (3,553)
7	Citizens Acquisition Discount	$ (30,709,738)	$ -	$ (30,709,738)	$ (55,126,579)	$ -	$ (55,126,579)
8	Less: Accum. Amort. - Citizens Acq. Discount	$ (3,935,647)	$ -	$ (3,935,647)	$ (6,658,438)	$ -	$ (6,658,438)
9	Net Citizens Acquisition Discount	$ (26,774,091)	$ -	$ (26,774,091)	$ (48,468,141)	$ -	$ (48,468,141)
10	Total Net Utility Plant	$ 203,909,989	$ (1,527,588)	$ 202,382,401	$ 360,275,202	$ (2,514,427)	$ 357,760,775
11	Customer Advances for Construction	$ (11,235,876)	$ (589,152)	$ (11,825,028)	$ (12,759,773)	$ (589,152)	$ (13,348,925)
							$ -
12	Customer Deposits	$ (2,609,271)	$ -	$ (2,609,271)	$ (2,609,271)	$ -	$ (2,609,271)
							$ -
13	Accumulated Deferred Income Taxes	$ (10,606,875)	$ (196,256)	$ (10,803,131)	$ (18,474,527)	$ (196,256)	$ (18,670,783)
14	Total Deductions	$ (24,452,022)	$ (785,408)	$ (25,237,430)	$ (33,843,571)	$ (785,408)	$ (34,628,979)
15	Allowance for Working Capital	$ 2,364,921	$ (95,671)	$ 2,269,250	$ 2,364,921	$ (95,671)	$ 2,269,250
							$ -
16	Regulatory Assets	$ 492,590	$ -	$ 492,590	$ 492,590	$ -	$ 492,590
							$ -
17	Regulatory Liabilities	$ (22,372)	$ -	$ (22,372)	$ (22,372)	$ -	$ (22,372)
18	Total Rate Base	$ 182,293,106	$ (2,408,667)	$ 179,884,439	$ 329,266,770	$ (3,395,506)	$ 325,871,264

Notes and Source
Cols. A and D: UNS Gas Inc. filing, Schedule B-1

	Fair Value Calculation (Per Company)		
19	Original Cost	$ 182,293,106	
20	RCND	$ 329,266,770	
21	Total	$ 511,559,876	
22	Average (Fair Value)	$ 255,779,939	See Sch. A

	Fair Value Calculation (Per RUCO)		
23	Original Cost	$ 179,884,439	
24	RCND	$ 325,871,264	
25	Total	$ 505,755,703	
26	Average (Fair Value)	$ 252,877,851	See Sch. A

UNS Gas, Inc.
Summary of Rate Base Adjustments

Test Year Ended June 30, 2008

Line No.	Description	RUCO Adjustments	Construction Work in Progress/Post Test Year Plant B-1	Customer Advances B-2	Prepayments B-3	Cash Working Capital B-4	Customer Deposits B-5	Accumulated Deferred Income Taxes B-6
1	Gross Utility Plant in Service	$ (1,527,588)	$ (1,527,588)					
2	Less: Accumulated Depreciation	$ -						
3	Net Utility Plant in Service	$ (1,527,588)	$ (1,527,588)	$ -	$ -	$ -	$ -	$ -
4	Southern Union Acquisition Premium	$ -						
5	Less: Accum. Amort. - So. Union Acq. Premium	$ -						
6	Net Southern Union Acquisition Premium	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Citizens Acquisition Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Less: Accum. Amort. - Citizens Acq. Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Net Citizens Acquisition Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Total Net Utility Plant	$ (1,527,588)	$ (1,527,588)	$ -	$ -	$ -	$ -	$ -
11	Customer Advances for Construction	$ (589,152)		$ (589,152)				
12	Customer Deposits	$ -						
13	Accumulated Deferred Income Taxes	$ (196,256)						$ (196,256)
14	Total Deductions	$ (785,408)	$ -	$ (589,152)	$ -	$ -	$ -	$ (196,256)
15	Allowance for Working Capital	$ (95,671)			$ (95,671)			
16	Regulatory Assets	$ -						
17	Regulatory Liabilities	$ -						
18	Total Rate Base	$ (2,408,667)	$ (1,527,588)	$ (589,152)	$ (95,671)	$ -	$ -	$ (196,256)

UNS Gas, Inc.
Adjusted Net Operating Income

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C
Page 1 of 1

Line No.	Description	As Adjusted by UNS (A)	RUCO Adjustments (B)	As Adjusted by RUCO (C)
	Operating Revenues			
1	Gas Retail Revenues	$ 51,157,763	$ 516,003	$ 51,673,766
2	Other Operating Revenues	$ 1,744,743	$ -	$ 1,744,743
3	Total Operating Revenues	$ 52,902,506	$ 516,003	$ 53,418,509
	Operating Expenses			
4	Purchased Gas	$ 397,635	$ -	$ 397,635
5	Other O&M Expenses	$ 24,719,113	$ (1,378,677)	$ 23,340,436
6	Depreciation & Amortization	$ 8,240,005	$ (58,107)	$ 8,181,898
7	Taxes Other Than Income Taxes	$ 4,342,078	$ (524,318)	$ 3,817,760
8	Income Taxes	$ 3,603,671	$ 986,328	$ 4,589,999
9	Total Operating Expenses	$ 41,302,502	$ (974,774)	$ 40,327,728
10	Net Operating Income	$ 11,600,004	$ 1,490,777	$ 13,090,781

Notes and Source
Col. A: UNS Gas Inc. filing, Schedule C-1
Col. B: Staff Schedule C.1

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2008

Line No.	Description	RUCO Adjustments	Gas Retail Revenue	Depreciation & Property Taxes for CWIP	Incentive Compensation	Stock-Based Compensation Expense	Supplemental Executive Retirement Plan Expense	American Gas Association Dues
			C-1	C-2	C-3	C-4	C-5	C-6
	Operating Revenues							
1	Gas Retail Revenues	$ 516,003	$ 516,003					
2	Other Operating Revenues	$ -						
3	Total Operating Revenues	$ 516,003	$ 516,003	$ -	$ -	$ -	$ -	
	Operating Expenses							
4	Purchased Gas	$ -						
5	Other O&M Expenses	$ (1,378,677)		$ (11,351)	$ (140,484)	$ (266,399)	$ (101,021)	$ (16,762)
6	Depreciation & Amortization	$ (58,107)		$ (58,107)				
7	Taxes Other Than Income Taxes	$ (524,318)		$ (25,584)	$ (12,027)			
9	PRE-TAX OPERATING EXPENSES	$ (1,961,102)	$ -	$ (95,042)	$ (152,511)	$ (266,399)	$ (101,021)	$ (16,762)
10	PRE-TAX OPERATING INCOME	$ 2,477,105	$ 516,003	$ 95,042	$ 152,511	$ 266,399	$ 101,021	$ 16,762
11	Income Taxes	$ 986,328	$ 199,167	$ 36,684	$ 58,866	$ 102,825	$ 38,992	$ 6,470
11	TOTAL OPERATING EXPENSES	$ (974,774)	$ 199,167	$ (58,358)	$ (93,645)	$ (163,574)	$ (62,029)	$ (10,292)
12	OPERATING INCOME	$ 1,490,777	$ 316,836	$ 58,358	$ 93,645	$ 163,574	$ 62,029	$ 10,292

Notes and Source

Combined Effective Tax Rate 38.5980%

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2008

Line No.	Description	Outside Services Legal Expense	Fleet Fuel Expense	Rate Case Expense	Interest Synchronization	Property Tax Expense	2010 Pay Increase
		C-7	C-8	C-9	C-10	C-11	C-12
	Operating Revenues						
1	Gas Retail Revenues						
2	Other Operating Revenues						
3	Total Operating Revenues		$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas						
5	Other O&M Expenses	$ (217,674)	$ (240,913)	$ (158,333)			$ (225,740)
6	Depreciation & Amortization						
7	Taxes Other Than Income Taxes		$ (230,913)			$ (230,913)	$ (24,881)
9	PRE-TAX OPERATING EXPENSES	$ (217,674)	$ (471,826)	$ (158,333)	$ -	$ (230,913)	$ (250,621)
10	PRE-TAX OPERATING INCOME	$ 217,674	$ 471,826	$ 158,333	$ -	$ 230,913	$ 250,621
11	Income Taxes	$ 84,018	$ 182,115	$ 61,113	$ 30,215	$ 89,128	$ 96,735
11	TOTAL OPERATING EXPENSES	$ (133,656)	$ (289,711)	$ (97,220)	$ 30,215	$ (141,785)	$ (153,886)
12	OPERATING INCOME	$ 133,656	$ 289,711	$ 97,220	$ (30,215)	$ 141,785	$ 153,886

Notes and Source

Combined Effective Tax Rate 38.5980%

UNS Gas, Inc.
Capital Structure & Cost Rates

Test Year Ended June 30, 2008

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)
	I. UNS Gas - Proposed				
1	Short-Term Debt	n/a	n/a	3.95%	n/a
2	Long-Term Debt	$ 99,265	50.01%	6.49%	3.25%
3	Common Stock Equity	$ 99,242	49.99%	11.00%	5.50%
4	Total Capital	$ 198,507	100.00%		8.75%
5	Fair Value Adjustment				0.79%
6	UNS Gas Proposed Return				9.54%
	II. UNS Gas Proposed to Show Equivalent Requested ROE				
7	Short-Term Debt	$ -	0.00%	3.95%	n/a
8	Long-Term Debt	$ 99,265	50.01%	6.49%	3.25%
9	Common Stock Equity	$ 99,242	49.99%	**12.58%**	6.29%
10	Total Capital	$ 198,507	100.00%		9.54%
	III. RUCO - Proposed Rate of Return for Original Cost Rate Base				
11	Short-Term Debt	n/a	n/a	3.95%	n/a
12	Long-Term Debt	$ 99,265	50.01%	6.49%	3.25%
13	Common Stock Equity	$ 99,242	49.99%	8.61%	4.30%
14	Total Capital	$ 198,507	100.00%		7.55%
15	Difference				-1.99%
16	Weighted Cost of Debt				3.25%

Notes and Source
Lines 1-4 taken from UNS Gas Inc. filing, Schedule D-1
Lines 5&6: UNS Gas filing, Schedule A
Lines 11-14: RUCO witness William Rigsby

UNS Gas, Inc.
Capital Structure & Cost Rates

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule D

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)
	Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation				
1	Short-Term Debt	n/a	n/a	3.95%	n/a
2	Long-Term Debt	$ 99,265	50.01%	6.49%	3.25%
3	Common Stock Equity	$ 99,242	49.99%	6.11% [a]	3.05%
4	Total Capital	$ 198,507	100.00%		6.30%
	Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation				
5	Short-Term Debt	$ -	0.00%	3.95%	n/a
6	Long-Term Debt	$ 99,265	50.01%	6.49%	3.25%
7	Common Stock Equity	$ 99,242	49.99%	8.61%	4.30%
8	Total Capital	$ 198,507	100.00%		7.55%
9	Fair Value Adjustment				-2.50% [b]
10	UNS Gas Proposed Return				5.05%
	Calculation 3 - With Fair Value Rate Base Increment at Zero Cost				
11	Short-Term Debt	$ -	0.00%	3.95%	0.00%
12	Long-Term Debt	$ 89,952,641	35.57%	6.49%	2.31%
13	Common Stock Equity	$ 89,931,798	35.56%	8.61%	3.06%
14	Capital financing OCRB	$ 179,884,439			
15	Appreciation above OCRB not recognized on utility's books	$ 72,993,413	28.87%	0% [c]	0.00%
16	Total capital supporting FVRB	$ 252,877,852	100.00%		5.37%
	Calculation 4 - With Fair Value Rate Base Increment at 1.25 Percent				
17	Short-Term Debt	$ -	0.00%	3.95%	0.00%
18	Long-Term Debt	$ 89,952,641	35.57%	6.49%	2.31%
19	Common Stock Equity	$ 89,931,798	35.56%	8.61%	3.06%
20	Capital financing OCRB	$ 179,884,439			
21	Appreciation above OCRB not recognized on utility's books	$ 72,993,413	28.87%	1.25% [d]	0.36%
22	Total capital supporting FVRB	$ 252,877,852	100.00%		5.73%

Notes and Source

[a] Per RUCO witness William Rigsby, inflation to remove from OCRB-based ROE: -2.50%

[b] Per RUCO witness Rigsby, inflation to remove from OCRB-based Overall Rate of Return: -2.50%

[c] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

[d] Approximates the mid-point of a range from zero to 2.5 percent, with 2.5 percent representing an approximate real risk-free rate of return

Lines 11-22, Col.A:

Fair Value Rate Base	$ 252,877,851	Schedule A
Original Cost Rate Base	$ 179,884,439	Schedule A
Difference	$ 72,993,413	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

UNS Gas, Inc.
Construction Work in Progress/Post Test Year Plant

Test Year Ended June 30, 2008

Line No.	Description	Amount	Reference
1	Remove Construction Work in Progress	$ (1,527,588)	A&B

Notes and Source

A: UNS Gas Filing, Schedule B-2, page 2, line 1
B: Testimony of RUCO witness Ralph Smith

UNS Gas, Inc.
Customer Advances

Test Year Ended June 30, 2008

Line No.	Description	Amount	Reference
1	Use Test Year End Balance	$ (589,152)	A&B

Notes and Source
A: UNS Gas Filing, Schedule B-2, page 3, Line 11
B: Testimony of RUCO witness Ralph Smith

UNS Gas, Inc.
Prepayments

Test Year Ended June 30, 2008

Line No.	Description	Amount	Reference
1	Use Test Year End Balance	$ (95,671)	A&B

Notes and Source

A: UNS Gas Filing, Schedule B-5, page 2, line 3
B: Testimony of RUCO witness Ralph Smith

UNS Gas, Inc.
Accumulated Deferred Income Taxes

Test Year Ended June 30, 2008

Line No.	Description	Per UNS Gas (A)	Per RUCO (B)	Adjustment (C)
	Account 190			
1	CIAC	$ 2,436,909	$ 2,436,909	$ -
2	Customer Advances	$ 4,402,955	$ 4,402,955	$ -
3	Customer Advances - CWIP	$ (227,413)		$ 227,413
4	Dividend Equivalents	$ 17,952		$ (17,952)
5	Restricted Stock	$ 24,316		$ (24,316)
6	Restricted Stock - Directors	$ 55,281		$ (55,281)
7	Stock Options	$ 155,708		$ (155,708)
8	Vacation	$ 169,367		$ (169,367)
9	Total Account 190	$ 7,035,076	$ 6,839,864	$ (195,211)
	Account 282			
10	Net Plant ADIT	$ (17,452,856)	$ (17,452,856)	$ -
	Account 283			
11	CARES Reg Asset	$ (190,140)	$ (190,140)	$ -
12	Pension	$ 1,045		$ (1,045)
13	Total Account 283	$ (189,095)	$ (190,140)	$ (1,045)
14	**Net ADIT**	$ (10,606,875)	$ (10,803,131)	$ (196,256)

Notes and Source
A: UNS Gas workpaper UNSG0571/02839
B: Testimony of RUCO witness Ralph Smith

UNS Gas, Inc.
Adjustment to Annualize Gas Retail Revenue

Docket No. G-04204A-08-0571
Schedule C-1

Test))rmation Has Been Redacted**

Line No.	Description		Amount	Reference
1	UNS Gas Adjustment to Annualize Gas Retail Revenue	$	(516,003)	A
2	RUCO Recommended Adjustment to Annualized Gas Retail Revenue	$	-	B
3	Adjustment to Annualize Gas Retail Revenue	$	516,003	L2 - L1

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 1, line 1

B: See testimony

FERC 480/481/482

UNS Gas, Inc.
Remove Depreciation & Property Taxes for CWIP

Test Year Ended June 30, 2008

Line No.	Description	Account	Amount	Reference
1	CWIP Related Depreciation Expense	403	$ (58,107)	See page 2
2	Transportation Equip Depreciaton Charged to O&M	various	$ (11,351)	See page 2
3	CWIP Related Property Taxes	408	$ (25,584)	A
4	Total Adjustments		$ (95,042)	

Notes and Source

A: Testimony of RUCO witness Ralph Smith

5	CWIP included in Plant in Service Full Cash Value	$ (1,527,588)	Schedule B-1
6	Assessment Ratio	22.0%	Schedule C-11
7	Taxable Value	$ (336,069)	
8	Average Tax Rate	7.6127%	Schedule C-11
9	Property Tax	$ (25,584)	

UNS Gas, Inc.
Depreciation Related to Post Test Year Plant in Service

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-2

Line No.	Description	FERC Acct	Adjustment (A)	Depreciation Rate (B)	Depreciation Expense (C)
	I. Adjustment to Depreciation Expense				
1	Mains - Replacements & Public Improvements	376	$ (817,127)	2.07%	$ (16,915)
2	Services - Replacements	380	$ (271,433)	2.82%	$ (7,654)
3	Structures and Improvements	390	$ (39,408)	4.89%	$ (1,927)
4	Office Furniture	391	$ (12,493)	4.55%	$ (568)
5	Office Furniture	391	$ (5,548)	20.00%	$ (1,110)
6	Transportation Equipment Class 1	392	$ (10,744)	14.71%	$ (1,580)
7	Transportation Equipment Class 2	392	$ (34,232)	17.87%	$ (6,117)
8	Transportation Equipment Class 3	392	$ (17,568)	22.68%	$ (3,984)
9	Transportation Equipment Class 4	392	$ (15,608)	13.04%	$ (2,035)
10	Transportation Equipment Class 5	392	$ (14,770)	11.83%	$ (1,747)
11	Tools & Shop Equipment	394	$ (9,431)	4.00%	$ (377)
12	Laboratory Equipment	395	$ (186,174)	11.11%	$ (20,684)
13	Power Operated Equipment	396	$ (69,759)	10.49%	$ (7,318)
14	Communication Equipment	397	$ (23,293)	6.67%	$ (1,554)
15	TOTAL		$ (1,527,589)		$ (73,571)
16	Less Transportation Equipment		$ 92,922		$ 15,465
17	Plant Adjustment Other than Transportation Equipment		$ (1,434,667)		
18	Depreciation Expense Adjustment				$ (58,107)
	II. Adjustment to O&M Expense for Depreciation on Transportation Equipment				
19	Depreciation on Transportation Equipment	Line 16			$ (15,465)
20	Transportation Equipment Charged to O&M				73.40%
21	Adjustment to O&M Expense				$ (11,351)

Source:
Company Depreciation Workpaper UNSG0571/02244 and related Excel file

UNS Gas, Inc.
Incentive Compensation

Docket No. G-04204A-08-0571
Schedule C-3
Page 1 of 1

Test Year Ended June 30, 2008

Line No.	Description	Amount	Reference
1	Adjustment to Incentive Compensation Expense	$ (140,484)	A
2	Adjustment to Taxes Other Than Income	$ (12,027)	A

Notes and Source

A: Per Company's workpapers showing calculation of Incentive Compensation adjustment (except where noted)

FERC Acct	FERC Account Description	Company Amount	Disallowance Percentage	RUCO Adjusted Amount
870	Transportation Operation Supervision and Engineering	$ 26,217	50%	$ (13,109)
874	Distribution - Mains & Services Expense	$ 48,980	50%	$ (24,490)
878	Distribution - Meter Expense	$ -	50%	$ -
880	Distribution Other Expenses	$ 31,315	50%	$ (15,658)
887	Distribution - Maintenance of Mains	$ 35,188	50%	$ (17,594)
903	Customer Records/Collections Expense	$ -	50%	$ -
920	Administrative & General Salaries	$ 139,268	50%	$ (69,634)
		$ 280,968		$ (140,484)
408	Taxes Other Than Income Taxes	$ 24,054	50%	$ (12,027)

UNS Gas, Inc.
Stock-Based Compensation Expense

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-4

Line No.	Description	Amount	Reference
1	Stock Based Compensation Expense	$ (266,399)	A
2	Adjustment to Taxes Other Than Income	N/A	B

Notes and Source

A Supplemental Response to RUCO 1.46

FERC Acct	Description	Company Amount	Disallowance Percentage	RUCO Adjustment Amount
	BEGIN UNSG CONFIDENTIAL			
	END UNSG CONFIDENTIAL			
	Total	$ 266,399		$ (266,399)

UNS Gas, Inc.
Supplemental Executive Retirement Plan Expense

Test Year Ended June 30, 2008

Line No.	Description	Amount	Reference
1	Supplemental Executive Retirement Plan Expense	$ (101,021)	A

Notes and Source

A Response to Staff data request TF 6.64

FERC Account 926

UNS Gas, Inc.
American Gas Association Dues

Test Year Ended June 30, 2008

Line No.	Description	RUCO Adjustment (A)	Company Adjustment (B)	Net RUCO Adjustment (C)	Reference
1	Test Year AGA Dues Per Filing	$ 46,694	$ 46,694		A
2	Recommended AGA Dues	$ 28,016	$ 44,779		B
3	Recommended disallowance	$ (18,678)	$ (1,915)	$ (16,762)	C

Notes and Source

A: Response to TF 6.54, UNS Gas Workpaper UNSG0571/02500, RUCO 1.48

2007 Invoice	$ 45,508	50%	$ 22,754
2008 Invoice	$ 47,879	50%	$ 23,940
			$ 46,694

B:

	Per RUCO	Per UNS Gas
2007 AGA Dues Per Filing	$ 46,694	$ 46,694
Recommended disallowance	$ (18,678)	$ (1,915)
Recommended AGA Dues	$ 28,016	$ 44,779

C:

	Per RUCO	Per UNS Gas	
2007 AGA Dues Per Filing	$ 46,694	$ 47,879	
Recommended disallowance %	40% D	4%	
Recommended disallowance	$ (18,678)	$ (1,915)	$ (16,762)

D: See testimony and page 2 of this schedule

UNS Gas, Inc.
American Gas Association
Schedule of Expenses by NARUC Category

Docket No. G-04204A-08-0571
Schedule C-6

		March 2005 NARUC Audit Report for Year Ended 12/31/02		AGA 2007 Budget			AGA 2008 Budget		
Line No.	NARUC Operating Expense Category	% of Dues	Recommended Disallowance	% of Dues	With G&A Allocated	Recommended Disallowance	% of Dues	With G&A Allocated	Recommended Disallowance
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Public Affairs	24.13%	24.13%	23.29%	28.67%	28.67%	24.44%	30.63%	30.63%
2	Advertising			1.39%	1.71%	1.71%	1.18%	1.48%	1.48%
3	Communications	15.53%							
4	Corporate Affairs and International	10.54%	10.54%	8.44%	10.39%	10.39%	9.14%	11.46%	11.46%
5	General Counsel & Corp Secretary	5.20%	2.60%	4.09%	5.04%	2.52%	4.17%	5.23%	2.62%
6	Regulatory Affairs	15.51%							
7	Policy Planning & Regulatory Affairs			14.76%	18.17%		15.78%	19.78%	
8	Marketing Department	2.37%	2.37%						
9	Operating & Engineering Services	15.85%		24.11%	29.68%		21.71%	27.21%	
10	Policy & Analysis	12.94%							
11	Industry Finance & Admin. Programs	4.75%		5.16%	6.35%		3.36%	4.21%	
12	General & Administrative			18.77%			20.22%		
13	Total Expenses	106.82%	39.64%	100.01%	100.01%	43.29%	100.00%	100.00%	46.19%
14	Lobbying per IRC Section 162			2%			4%		

Notes and Source

Col.A: March 2005 Annual Audit Report on the Expenditures of the American Gas Association for the 12 month period ended December 31, 2002

Col.C: From Docket No. G-01551A-07-0504, Southwest Gas' Response to Staff data request STF-6-52; also see UNSG0571/07347

Col.F: From Docket No. G-01551A-07-0504, Southwest Gas' Response to Staff data request STF-6-50(b); also see UNSG0571/07348

UNS Gas, Inc.
Outside Services Legal Expense

Test Year Ended June 30, 2008

Line No.	Description	Amount	Reference
1	UNS Gas Request for Non-Rate Case Legal Expense	$ 389,539	A
2	RUCO recommendation	$ 171,865	B
3	Adjustment to Outside Services Legal Expense	$ (217,674)	

Notes and Source

A	UNS Gas Workpapers including UNSG0571/02563 - 02574		
B	Amount of past El Paso Gas legal expense included in UNS Gas' request:		
4		2005	$ 361,233
5		2006	$ 395,247
6		2007	$ 196,203
7		Total	$ 952,683
8		Three-Year Average	$ 317,561
9	Test Year Amount		$ 99,887
10	Company request for past El Paso Gas legal expense over test year actual		$ 217,674
11	Company Normalized Amount without past El Paso Gas Legal Cost		$ 71,978
12	Increase over Test Year Actual for Past El Paso Gas Legal Expense		$ 217,674
13	Test Year Actual without Legal Expense for 2006 Rate Case		$ 83,555
14	Amount over Test Year to Normalize other legal costs (not El Paso Gas)		$ 88,310
15	Recommended normalized level		$ 171,865

FERC Account 923

UNS Gas, Inc.
Fleet Fuel Expense

Docket No. G-04204A-08-0571
Schedule C-8

Test Year Ended June 30, 2008

Line No.	Description		Amount	Reference
1	UNS Gas Adjustment to Fleet Fuel Expense	$	732,092	A
2	RUCO Recommended Fleet Fuel Expense	$	491,179	B
3	Adjustment to Fleet Fuel Expense	$	(240,913)	L2 - L1

Notes and Source

A RUCO 1.94

2006		214,935	Sch C-8.1
2007		218,847	Sch C-8.1
2008		213,074	Sch C-8.1
3 Yr Avg		215,619	
Price of fuel	$	2.278	B
Normalized fuel expense	$	491,179	

B ArizonaGasPrices.com

UNS Gas, Inc.
Fleet Fuel Expense

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-8.1

	Gallons			
Month	**2006**	**2007**	**2008**	**2009**
Jan	20,562	18,777	22,234	21,061
Feb	16,694	16,937	18,597	16,214
Mar	18,731	19,618	18,173	17,150
Apr	17,743	17,833	18,840	17,187
May	19,073	18,946	18,942	
Jun	18,290	18,310	14,687	
Jul	18,709	20,070	18,641	
Aug	19,698	19,460	17,712	
Sep	18,828	17,468	17,924	
Oct	17,542	18,625	18,345	
Nov	16,567	17,086	15,368	
Dec	12,498	15,717	13,611	
Total	214,935	218,847	213,074	71,612

Source:
RUCO 1.94

UNS Gas, Inc.
Rate Case Expense

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-9
Page 1 of 1

Line No.	Description	Amount	Reference
	I. Normalized Allowance for Rate Case Cost		
1	UNS Gas Rate Case Expense per Company Filing	$ 200,000	A
2	RUCO Recommended Rate Case Expense	$ 100,000	B
3	Adjustment for Normalized Rate Case Expense Allowance	$ (100,000)	L.2 - L.1
	II. Remove Prior Rate Case Cost from Test Year		
4	Remove Prior Rate Case Cost from Test Year	$ (58,333)	C
	III. Total Adjustment to UNS Gas' Proposed Rate Case Expense		
5	Total Adjustment to UNS Gas' Proposed Rate Case Expense	$ (158,333)	L.3 + L.4

Notes and Source

A: UNS Gas filing, Schedule C-2, page 3, line 5

B: RUCO Recommended Annual Allowance for NormalizedRate Case Expense

6	Recommended Total Allowance for Current Rate Case	$ 300,000
7	Normalized Over Three Years	3
8	Normalized Annual Allowance for Rate Case Expense	$ 100,000

C: Response to Staff data request TF 6.68

UNS Gas, Inc.
Interest Synchronization

Test Year Ended June 30, 2008

Docket No. G-04204A-06-0463
Schedule C-10

Line No.	Description		Amount	Reference
1	Adjusted rate base	$	179,884,439	Schedule B
2	Weighted cost of debt		3.25%	Schedule D
3	Synchronized interest deduction	$	5,846,244	Line 1 x Line 2
4	Synchronized interest deduction per UNS Gas	$	5,924,526	Note A
5	Difference (decreased) increased interest deduction	$	(78,282)	Line 3 - Line 4
6	Combined federal and state income tax rates		38.598%	B
7	Increase (decrease) to income tax expense	$	30,215	

Notes and Source

A UNS Gas filing, Schedule B-5, page 3 of 3, line 18

B Schedule A-1

UNS Gas, Inc.
Property Tax Expense

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-11
Page 1 of 1

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Increase to Property Tax Expense	$ 1,354,074	A
2	RUCO Proposed Increase to Property Tax Expense	$ 1,123,161	B
3	Adjustment to Property Tax Expense	$ (230,913)	L2 - L1

Notes and Source
A: UNS Gas Filing, Schedule C-2, page 4, line 7
B: Amounts taken from Company workpapers used to calculate its property tax expense adjustment

	Utility Plant in Service Taxes	Transmission	Distribution	General/ Intangible	Total
4	Total Net Plant in Service - Rate Base	$ 12,465,045	$ 177,788,678	$ 13,656,266	$ 203,909,989
5	Less: Licensed Transportation in Rate Base			$ (3,786,247)	$ (3,786,247)
6	Less: Land Cost & Rights of Way in Rate Base	$ (55,514)	$ (171,343)	$ (332,698)	$ (559,555)
7	Less: Environmental Property in Rate Base	$ (539,039)	$ (3,264,648)	$ (238,708)	$ (4,042,395)
8	Plus: Land FCV Per Arizona Dept. of Revenue		$ 966,162	$ 93,000	$ 1,059,162
9	Plus: Materials & Supplies in Rate Base		$ 2,010,060		$ 2,010,060
10	Plant in Service Full Cash Value	$ 11,870,492	$ 177,328,909	$ 9,391,613	$ 198,591,014
11	Assessment Ratio*	22.0%	22.0%	22.0%	
12	Taxable Value	$ 2,611,508	$ 39,012,360	$ 2,066,155	$ 43,690,023
13	Average Tax Rate	7.6127%	7.6127%	7.6127%	
14	Property Tax	$ 198,806	$ 2,969,894	$ 157,290	$ -
15	Environmental Property in Rate Base	$ 539,039	$ 3,264,648	$ 238,708	
16	Statutory Full Cash Value Adjustment	50%	50%	50%	
17	Environmental Full Cash Value	$ 269,520	$ 1,632,324	$ 119,354	$ -
18	Assessment Ratio*	22.0%	22.0%	22.0%	22.0%
19	Taxable Value	$ 59,294	$ 359,111	$ 26,258	$ -
20	Average Tax Rate	7.6127%	7.6127%	7.6127%	
21	Property Tax	$ 4,514	$ 27,338	$ 1,999	$ -
22	Total Property Taxes	$ 203,320	$ 2,997,232	$ 159,289	$ 3,359,841
23	Property Taxes on Leased Property	$ -	$ -	$ 19,325 a	$ 19,325
24	Total Property Tax Expense	$ 203,320	$ 2,997,232	$ 178,614	$ 3,379,166
25	Less: Recorded Property Taxes Excluding Call Center	$ (167,683)	$ (1,981,552)	$ (106,770)	$ (2,256,005)
26	Property Tax Expense Adjustment	$ 35,637	$ 1,015,680	$ 71,844	$ 1,123,161

a: Property Tax for Leases calculated as follows (amounts taken from Company workpaper)

	Cottonwood Lease	Primary Value	Secondary Value	Total
27	Full Cash Value	$ 962,504	$ 1,145,159	
28	Assessment Ratio*	22.0%	22.0%	
29	Taxable Value	$ 211,751	$ 251,935	
30	Tax Rate	5.6883%	1.3479%	
31	Property Tax	$ 12,045	$ 3,396	$ 15,441
	Nogales Lease			
32	Full Cash Value	$ 432,493		
33	Assessment Ratio*	22.0%		
34	Taxable Value	$ 95,148		
35	Tax Rate	10.2038%		
36	Property Tax	$ 9,709		
37	Percentage Allocated to UNS Gas	40%		
38	Property Taxes Allocated	$ 3,884		$ 3,884
39	Total Lease Taxes			$ 19,325

* 2009 Arizona Statutory Assessment Ratio 22.0%

FERC 408

UNS Gas, Inc.
Payroll and Payroll Tax Expense

Test Year Ended June 30, 2008

Docket No. G-04204A-08-0571
Schedule C-12

Line No.	Description	Amount (A)	Reference
1	Total Adjusted O&M Payroll Expense Including Overtime Per Filing	$ 7,750,405	A
2	RUCO Recommended Adjusted O&M Payroll Expense Including Overtime	$ 7,524,665	B
3	RUCO Adjustment to Adjusted O&M Payroll Expense	$ (225,740)	L2 - L1
4	Total Pro Forma Payroll Tax Expense Per Filing	$ 888,084	page 2
5	RUCO Recommended Pro Forma Payroll Tax Expense	$ 863,202	page 2
6	RUCO Adjustment to Payroll Tax Expense	$ (24,882)	L5 - L4

Notes and Source

Company workpaper UNSG0571/02586 and related Excel file

A: Amount from Company workpaper UNSG0571/02586 calculated from the following amounts:

7	2009 & 2010 Wage Increase	$ 6,034,999
8	Adjusted Overtime	$ 914,247
9	Estimate Allocated from CLR Accounts	$ 801,159
10	Total Adjusted O&M Payroll Expense Including Overtime Per Filing	$ 7,750,405

B: RUCO recommended amount calculated as follows:

11	2009 Wage Increase (reflects removal of 3% wage increase for 2010)	$ 5,859,222
12	Adjusted Overtime	$ 887,618
13	Estimate Allocated from CLR Accounts	$ 777,824
14	RUCO Recommended Adjusted O&M Payroll Expense Including Overtime	$ 7,524,665

UNS Gas, Inc.
Payroll and Payroll Tax Expense

Test Year Ended June 30, 2008

Line No.	Description	Per UNS Gas (A)	Per RUCO (B)	RUCO Adjustment (C)
	Medicare			
1	Total Adjusted Payroll Including Overtime	$ 11,166,981	$ 10,841,729	
2	Medicare Tax Rate	1.45%	1.45%	
3	Pro Forma Medicare Tax Per Filing	$ 161,921	$ 157,205	$ (4,716)
	OASDI			
4	Total Adjusted Payroll Including Overtime	$ 11,166,981	$ 10,841,729	
5	Less: Wages in Excess of $102,000	$ (99,577)	$ (99,577)	
6	OASDI Tax Base	$ 11,067,404	$ 10,742,152	
7	OASDI Tax Rate	6.20%	6.20%	
8	Pro Forma OASDI Tax	$ 686,179	$ 666,013	$ (20,166)
	Federal/State Unemployment Tax			
	Number of Employees			
9	UNSG Classified	118	118	
10	UNSG Unclassified	86	86	
11	Total Employees	204	204	
12	Taxable Wages	$ 7,000	$ 7,000	
13	Tax Base	$ 1,428,000	$ 1,428,000	
14	Tax Rate	2.80%	2.80%	
15	Pro Forma FUI/SUI	$ 39,984	$ 39,984	$ -
16	Total Pro Forma Payroll Tax Expense	$ 888,084	$ 863,202	$ (24,882)

Notes and Source
Col. A: Amounts from Company workpaper UNSG0571/02608
Col. B: Total adjusted payroll including overtime on Line 1 reflects 3% increase for 2009 only

Attachment RCS-3

Excerpts from NARUC-sponsored Audits of the Expenditures of the American Gas Association

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31,1999)

JUNE 2001

COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue; Suite 200
Washington, D.C. 20005

Telephone No. (202) 1898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31,1999

EXPENSE CATEGORY	PERCENTAGE
Public Affairs	15.43%
Communications	11.64%
Media Communications:	
Commercial Equipment	4.47%
Environmental	0.74 %
Promotional	0.74%
Residential Equipment	2.96%
Corporate Affairs & International	11.30%
General Counsel & Corporate Secretary	4.02%
Regulatory Affairs	11.20%
Marketing Services	15.02%
Operating & Engineering Services	14.70%
Policy & Analysis	12.07%
Industry Finance & Admin. Programs	2.94 %
General & Administrative Expense	0.00%
TOTAL	107.23% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1999

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (5)	Adjusted Net Expense	% of Dues
03	Public Affairs	4,147,682	3, 4	(1,690,669)	455,752	2,912,765	15.43%
03	Communications		4	1,698,695	498,479	2,197,174	11.64%
08	Media Communications						
	Commercial Equipment	759,932	1,2	61,868	21,400	843,200	4.47%
	Environmental	126,708	1,2	10,316	3,568	140,592	0.74%
	Promotional	126,708	1,2	10,316	3,568	140,592	0.74%
	Residential Equipment	503,934	1,2	41,027	14,191	559,152	2.96%
06. 16	Corporate Affairs and International	1,483,688	3	(5,217)	655,144	2,133,615	11.30%
05	General Counsel & Corp. Secretary	588,436	3		170,907	759,343	4.02%
09	Regulatory Affairs	1,492,676	3	194,393	427,268	2,114,337	11.20%
08	Marketing Services	4,654,503	1, 2	(2,302,920)	484,237	2,835,820	15.02%
14	Operating & Engineering Services	1,949,534			826,051	2,775.585	14.70%
07	Policy & Analysis	1,374,743	1	277.704	626,659	2,279,106	12.07%
12	Industry Finance & Admin. Programs	498,349			56,969	555,318	2.94%
01.10.11	General & Administrative Expense	4,247,002	3	(2,809)	(4,244,193)		0.00%
	Grand Total	21,953,895		$ (1,707,296)	$ -	$ 20,246,599	107.23%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 Breakout of communications portion of division expenses
5 G&A allocated on basis of equivalent full-time employees during 1999.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1999

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
	Public affairs provides members with information on legislative developments: prepares testimony, comments, and filings regarding legislative activities; lobbies on behalf of the industry.
08	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
	Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
	Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels.
	Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applicationsof specific equipment.
	Institutional - to enhance the image of the natural gas industry as a business entity.
	Power Generation Natural Gas Equipment - explains cost-savings. energy-savings and other benefits provided by specific equipment for generating power.
	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
12	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.

05 General Counsel & Corporate Secretaw provides legal counsel to the Association

06 Corporate Affairs provides opportun'ities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.

09 Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.

08 Market Development assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

Donna's Copy LF-111

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31, 1998)

JANUARY 2000

COMMITTEE ON UTILITY ASSOCIATION OVERSIGHT

**National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue, N.W., Suite 200
Washington, D.C. 20005**

Telephone No. (202) 898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31, 1998

EXPENSE CATEGORY	PERCENTAGE
Communications	10.27%
MEDIA COMMUNICATIONS:	
Commercial Equipment	5.96%
Environmental	3.37%
Industrial Equipment	1.36%
Promotional	1.46%
Residential Equipment	8.40%
Finance & Administration Services	12.17%
General Counsel & Corporate Secretary	5.54%
Government Relations	23.86%
Marketing Services	16.20%
Meeting Services	-0.18%
Operating & Engineering Services	4.90%
Planning & Analysis	9.51%
General & Administrative Expense	0.00%
TOTAL	102.82% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1998

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (4)	Adjusted Net Expense	% of Dues
03	Communications	1,561,612	2	(2,679)	430,782	1,989,715	10.27%
13	Media Communications						
	Commercial Equipment	1,105,739	1,2	31,943	17,848	1,155,530	5.96%
	Environmental	625,598	1,2	18,072	10,098	653,768	3.37%
	Industrial Equipment	252,954	1,2	7,307	4,083	264,344	1.36%
	Promotional	270,820	1,2	7,823	4,372	283,015	1.46%
	Residential Equipment	1,557,378	1,2	44,990	25,139	1,627,507	8.40%
06	Finance & Administration Services	1,797,937	3	(13,893)	574,377	2,358,420	12.17%
05	General Counsel & Corp. Secretary	938,797	3	(8,566)	143,594	1,073,825	5.54%
09	Government Relations	3,802,555	3	22,459	800,025	4,625,039	23.86%
08	Marketing Services	2,693,462	1	(107,456)	553,863	3,139,869	16.20%
04	Meeting Services	(34,155)		-	-	(34,155)	-0.18%
14	Operating & Engineering Services	661,825		-	287,188	949,013	4.90%
07	Policy & Analysis	1,392,718		-	451,296	1,844,014	9.51%
01,10,11	General & Administrative Expense	3,302,665		-	(3,302,665)	0	0.00%
	Grand Total	19,929,905		$ 0	$ 0	$ 19,929,905	102.84%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 G&A allocated on basis of equivalent full-time employees during 1997.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1998

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
13	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media. Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas. Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels. Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applications of specific equipment. Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas. Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
06/ 16	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.
05	General Counsel & Corporate Secretary provides legal counsel to the Association.
09	Government Relations provides members with information on legislative and regulatory developments; prepares testimony, comments, and filings regarding legislative and regulatory activities; lobbies on behalf of the industry.
08	Marketing assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

04 Meeting Services and Membership Services provides support services for committee meetings and conferences. In addition, coordinates services provided to members.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

Excerpt from Florida PSC City Gas Company rate case 01152004

State of Florida

Public Service Commission

Capital Circle Office Center 2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE:DECEMBER 23, 2003

TO:DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES (BAYÓ)

FROM:DIVISION OF ECONOMIC REGULATION (BRINKLEY, BAXTER, DRAPER, GARDNER, HEWITT, KAPROTH, KENNY, LESTER, LINGO, C. ROMIG, SPRINGER, STALLCUP, WHEELER, WINTERS)
DIVISION OF COMPETITIVE SERVICES (MAKIN)
OFFICE OF THE GENERAL COUNSEL (JAEGER)

RE:DOCKET NO. 030569-GU - APPLICATION FOR RATE INCREASE BY CITY GAS COMPANY OF FLORIDA.

AGENDA:01/06/04 - REGULAR AGENDA - PROPOSED AGENCY ACTION - INTERESTED PERSONS MAY PARTICIPATE

CRITICAL DATES:5-MONTH EFFECTIVE DATE: JANUARY 15, 2004 (PAA RATE CASE)

SPECIAL INSTRUCTIONS:NONE

FILE NAME AND LOCATION:S:\PSC\ECR\WP\City Gas 030569-GU\
Final.RCM
Final Attachments 1-5.123
Final Attachments 6A-7P.123
Final Attachment 8.xls

ISSUE 39: Is City Gas's $(2,847) adjustment to Account 921, Office Supplies and Expenses, for American Gas Association membership dues appropriate?

RECOMMENDATION: No. Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for American Gas Association membership dues related to charitable contributions and advertising that is not informational or educational in nature. (C. ROMIG)

STAFF ANALYSIS: On MFR Schedule G-2, Page 17 of 34, the Company included $1,966,495 in its Account 921, Office Supplies and Expense for the 2003 interim year. Included in this amount is $39,277 related to American Gas Association (AGA) membership dues. This was inflated for customer growth and general inflation of 1.0232 to $40,188. On MFR G-2, Page 2 of 34, it removed $2,847 that was labeled as "attributable to lobbying." This represents an adjustment of 7.08%.

In City Gas's last rate case, In re: Request for rate increase by City Gas Company of Florida, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. In re: Application for a rate increase by City Gas Company of Florida, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Attachment RCS-5
Copies of UNS Gas' Responses to Data Requests and Workpapers Referenced in the Direct Testimony and Schedules of Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
TF 6-28	Working capital adjustment detail - Customer deposits	No	8	2 - 9
TF 6.64	Description of SERP and incentive compensation programs available to officers and employees	No	68	10 - 77
TF 6.103	UNS Gas' Accounting adjustments deviating from prior Commission decisions	No	1	78
TF 6.92	UNS Gas' description of incentive compensation plans	No	4	79 - 82
	UniSource Energy's March 23, 2009 Proxy Report (publicly available)	No	51	83 - 133
RUCO 1.94	UNS Gas' fleet fuel expense supporting data	No	4	134-137
	Public information on Arizona gasoline prices	No	5	138-142
TF 6.68	Explanation of rate case expense adjustment correction	No	3	143-145
RUCO 1.90	Current average known property tax rate	No	2	146-147
UNSG0571/02839	UNS Gas' Accumulated Deferred Income Taxes Workpaper	No	1	148
UNSG0571/02244 & related excel file	UNS Gas' Depreciation Workpapers	No	8	149-156
TF 6.54	American Gas Association Dues Expense	No	11	157-167
RUCO 1.48	Copies of American Gas Association Dues Invoices	No	4	168-171
UNSG0571/02500	UNS Gas' American Gas Association Dues Workpapers	No	1	172
UNSG0571/02585-86	UNS Gas' Outside legal costs workpapers	No	12	173-184
UNSG0571/02563 - 74 & related excel file	UNS Gas' Payroll Expense Workpapers	No	2	185-186
UNSG0571/02608	UNS Gas' Payroll Tax Expense Workpapers	No	1	187
	Total Pages Including this Page		187	

**UNS GAS, INC.'S RESPONSE TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
April 17, 2009**

TF 6.28: For the Company's details of adjustments to working capital, B-5, page 2 of 3, M&S and Prepayments.

a. Please provide the monthly amounts of M&S for the 60 months ending December 31, 2008.
b. Please provide the monthly amounts of Prepayments for the 60 months ending December 31, 2008.

Please also provide the monthly amounts of Customer Deposits for the 60 months ending December 31, 2008.

RESPONSE:

a. Please see the Excel file TF 6.28(a) on the enclosed CD for the monthly amounts of M&S for the period January 2006 through December 2008. The prior months January 2004 – December 2005 were provided in the prior rate case.

b. Please see the Excel file TF 6.28(b) on the enclosed CD for the monthly amounts of Prepayments for the period January 2006 through December 2008. The prior months January 2004 – December 2005 were provided in the prior rate case.

c. Please see the Excel file TF 6.28(c) on the enclosed CD for the monthly amounts of Customer Deposits for the period January 2006 through December 2008. The prior months January 2004 – December 2005 were provided in the prior rate case.

The Excel files on the CD are <u>not</u> identified by Bates numbers.

RESPONDENT: Mina Briggs

WITNESS: Dallas Dukes

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28a - Materials and Supplies 60 months ending December 2008

JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
12600	Undistributed Stores Expense	JAN-06	$110,243.38	$44,419.42	$154,662.80
12500	Materials & Supplies		$1,888,849.07	$156,693.08	$2,045,542.15
		Sum	$1,999,092.45	$201,112.50	$2,200,204.95
12500	Materials & Supplies	FEB-06	$2,045,542.15	($134,579.89)	$1,910,962.26
12600	Undistributed Stores Expense		$154,662.80	$98,892.29	$253,555.09
		Sum	$2,200,204.95	($35,687.60)	$2,164,517.35
12500	Materials & Supplies	MAR-06	$1,910,962.26	$10,218.98	$1,921,181.24
12600	Undistributed Stores Expense		$253,555.09	$34,599.12	$288,154.21
		Sum	$2,164,517.35	$44,818.10	$2,209,335.45
12500	Materials & Supplies	APR-06	$1,921,181.24	($187,979.01)	$1,733,202.23
12600	Undistributed Stores Expense		$288,154.21	($28,702.16)	$259,452.05
		Sum	$2,209,335.45	($216,681.17)	$1,992,654.28
12500	Materials & Supplies	MAY-06	$1,733,202.23	$139,631.20	$1,872,833.43
12600	Undistributed Stores Expense		$259,452.05	$4,383.75	$263,835.80
		Sum	$1,992,654.28	$144,014.95	$2,136,669.23
12600	Undistributed Stores Expense	JUN-06	$263,835.80	($43,329.01)	$220,506.79
12500	Materials & Supplies		$1,872,833.43	$106,638.95	$1,979,472.38
		Sum	$2,136,669.23	$63,309.94	$2,199,979.17
12500	Materials & Supplies	JUL-06	$1,979,472.38	$5,856.46	$1,985,328.84
12600	Undistributed Stores Expense		$220,506.79	($10,998.56)	$209,508.23
		Sum	$2,199,979.17	($5,142.10)	$2,194,837.07
12500	Materials & Supplies	AUG-06	$1,985,328.84	$19,582.02	$2,004,910.86
12600	Undistributed Stores Expense		$209,508.23	($1,141.18)	$208,367.05
		Sum	$2,194,837.07	$18,440.84	$2,213,277.91
12500	Materials & Supplies	SEP-06	$2,004,910.86	$32,555.25	$2,037,466.11
12600	Undistributed Stores Expense		$208,367.05	$4,325.73	$212,692.78
		Sum	$2,213,277.91	$36,880.98	$2,250,158.89
12500	Materials & Supplies	OCT-06	$2,037,466.11	($47,414.74)	$1,990,051.37
12600	Undistributed Stores Expense		$212,692.78	$26,616.65	$239,309.43
		Sum	$2,250,158.89	($20,798.09)	$2,229,360.80
12500	Materials & Supplies	NOV-06	$1,990,051.37	$23,911.77	$2,013,963.14
12600	Undistributed Stores Expense		$239,309.43	($12,444.16)	$226,865.27
		Sum	$2,229,360.80	$11,467.61	$2,240,828.41
12500	Materials & Supplies	DEC-06	$2,013,963.14	($54,840.35)	$1,959,122.79
12600	Undistributed Stores Expense		$226,865.27	($24,623.30)	$202,241.97
		Sum	$2,240,828.41	($79,463.65)	$2,161,364.76
12500	Materials & Supplies	Jan-07	$1,959,122.79	($48,995.66)	$1,910,127.13
12600	Undistributed Stores Expense		$202,241.97	($9,677.83)	$192,564.14
		Sum	$2,161,364.76	($58,673.49)	$2,102,691.27
12500	Materials & Supplies	Feb-07	$1,910,127.13	$45,750.59	$1,955,877.72
12600	Undistributed Stores Expense		$192,564.14	$18,119.20	$210,683.34
		Sum	$2,102,691.27	$63,869.79	$2,166,561.06
12500	Materials & Supplies	Mar-07	$1,955,877.72	($44,629.56)	$1,911,248.16
12600	Undistributed Stores Expense		$210,683.34	($12,384.75)	$198,298.59
		Sum	$2,166,561.06	($57,014.31)	$2,109,546.75
12500	Materials & Supplies	Apr-07	$1,911,248.16	$75,730.94	$1,986,979.10

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28b. Prepayments
JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
14050	Prepaid Taxes	JAN-06	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$181,140.02	($32,100.33)	$149,039.69
14100	Other Prepaids		$66,125.01	($26,262.89)	$39,862.12
		Sum	$247,265.03	($58,363.22)	$188,901.81
14100	Other Prepaids	FEB-06	$39,862.12	($3,623.83)	$36,238.29
14010	Prepaid Insurance		$149,039.69	($32,100.33)	$116,939.36
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$188,901.81	($35,724.16)	$153,177.65
14100	Other Prepaids	MAR-06	$36,238.29	$86,278.42	$122,516.71
14010	Prepaid Insurance		$116,939.36	($32,100.33)	$84,839.03
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$153,177.65	$54,178.09	$207,355.74
14100	Other Prepaids	APR-06	$122,516.71	($66,676.08)	$55,840.63
14010	Prepaid Insurance		$84,839.03	($32,100.33)	$52,738.70
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$207,355.74	($98,776.41)	$108,579.33
14100	Other Prepaids	MAY-06	$55,840.63	($6,980.08)	$48,860.55
14010	Prepaid Insurance		$52,738.70	($32,100.33)	$20,638.37
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$108,579.33	($39,080.41)	$69,498.92
14050	Prepaid Taxes	JUN-06	$0.00	$84,663.93	$84,663.93
14010	Prepaid Insurance		$20,638.37	$305,130.13	$325,768.50
14100	Other Prepaids		$48,860.55	$88,268.37	$137,128.92
		Sum	$69,498.92	$478,062.43	$547,561.35
14100	Other Prepaids	JUL-06	$137,128.92	($6,980.08)	$130,148.84
14010	Prepaid Insurance		$325,768.50	$22,895.58	$348,664.08
14050	Prepaid Taxes		$84,663.93	($9,673.15)	$74,990.78
		Sum	$547,561.35	$6,242.35	$553,803.70
14100	Other Prepaids	AUG-06	$130,148.84	($6,980.08)	$123,168.76
14010	Prepaid Insurance		$348,664.08	($32,714.42)	$315,949.66
14050	Prepaid Taxes		$74,990.78	($19,697.77)	$55,293.01
		Sum	$553,803.70	($59,392.27)	$494,411.43
14100	Other Prepaids	SEP-06	$123,168.76	$37,376.07	$160,544.83
14010	Prepaid Insurance		$315,949.66	($32,714.42)	$283,235.24
14050	Prepaid Taxes		$55,293.01	($22,107.56)	$33,185.45
		Sum	$494,411.43	($17,445.91)	$476,965.52
14100	Other Prepaids	OCT-06	$160,544.83	($11,316.27)	$149,228.56
14010	Prepaid Insurance		$283,235.24	($32,714.42)	$250,520.82
14050	Prepaid Taxes		$33,185.45	($16,744.54)	$16,440.91
		Sum	$476,965.52	($60,775.23)	$416,190.29
14100	Other Prepaids	NOV-06	$149,228.56	($11,316.27)	$137,912.29
14010	Prepaid Insurance		$250,520.82	($32,714.42)	$217,806.40
14050	Prepaid Taxes		$16,440.91	($16,440.91)	$0.00
		Sum	$416,190.29	($60,471.60)	$355,718.69
14100	Other Prepaids	DEC-06	$137,912.29	($460.32)	$137,451.97
14010	Prepaid Insurance		$217,806.40	($32,714.42)	$185,091.98
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$355,718.69	($33,174.74)	$322,543.95
14010	Prepaid Insurance	JAN-07	$185,091.98	($32,714.42)	$152,377.56
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$137,451.97	($4,336.19)	$133,115.78

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28b. Prepayments
JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
		Sum	$322,543.95	($37,050.61)	$285,493.34
14010	Prepaid Insurance	FEB-07	$152,377.56	($32,714.42)	$119,663.14
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$133,115.78	$33,587.15	$166,702.93
		Sum	$285,493.34	$872.73	$286,366.07
14100	Other Prepaids	MAR-07	$166,702.93	($109,794.38)	$56,908.55
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14010	Prepaid Insurance		$119,663.14	($32,714.42)	$86,948.72
		Sum	$286,366.07	($142,508.80)	$143,857.27
14010	Prepaid Insurance	APR-07	$86,948.72	($32,714.42)	$54,234.30
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$56,908.55	($8,128.52)	$48,780.03
		Sum	$143,857.27	($40,842.94)	$103,014.33
14100	Other Prepaids	MAY-07	$48,780.03	($8,128.52)	$40,651.51
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14010	Prepaid Insurance		$54,234.30	($32,714.42)	$21,519.88
		Sum	$103,014.33	($40,842.94)	$62,171.39
14010	Prepaid Insurance	JUN-07	$21,519.88	$326,172.83	$347,692.71
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$40,651.51	$107,126.78	$147,778.29
		Sum	$62,171.39	$433,299.61	$495,471.00
14010	Prepaid Insurance	JUL-07	$347,692.71	$21,532.58	$369,225.29
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$147,778.29	($8,128.52)	$139,649.77
		Sum	$495,471.00	$13,404.06	$508,875.06
14100	Other Prepaids	AUG-07	$139,649.77	($8,128.52)	$131,521.25
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14010	Prepaid Insurance		$369,225.29	($34,668.42)	$334,556.87
		Sum	$508,875.06	($42,796.94)	$466,078.12
14010	Prepaid Insurance	SEP-07	$334,556.87	($34,668.42)	$299,888.45
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$131,521.25	($38,924.09)	$92,597.16
		Sum	$466,078.12	($73,592.51)	$392,485.61
14010	Prepaid Insurance	OCT-07	$299,888.45	($34,668.42)	$265,220.03
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$92,597.16	$38,308.88	$130,906.04
		Sum	$392,485.61	$3,640.46	$396,126.07
14010	Prepaid Insurance	NOV-07	$265,220.03	($34,668.42)	$230,551.61
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14100	Other Prepaids		$130,906.04	($7,619.71)	$123,286.33
		Sum	$396,126.07	($42,288.13)	$353,837.94
14100	Other Prepaids	DEC-07	$123,286.33	$15,397.79	$138,684.12
14050	Prepaid Taxes		$0.00	$0.00	$0.00
14010	Prepaid Insurance		$230,551.61	($34,668.42)	$195,883.19
		Sum	$353,837.94	($19,270.63)	$334,567.31
14050	Prepaid Taxes	JAN-08	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$195,883.19	($34,668.42)	$161,214.77
14100	Other Prepaids		$138,684.12	$40,061.70	$178,745.82
		Sum	$334,567.31	$5,393.28	$339,960.59
14050	Prepaid Taxes	FEB-08	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$161,214.77	($34,668.42)	$126,546.35

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28b. Prepayments
JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
14100	Other Prepaids		$178,745.82	($7,817.30)	$170,928.52
		Sum	$339,960.59	($42,485.72)	$297,474.87
14050	Prepaid Taxes	MAR-08	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$126,546.35	($34,668.42)	$91,877.93
14100	Other Prepaids		$170,928.52	$26,867.03	$197,795.55
		Sum	$297,474.87	($7,801.39)	$289,673.48
14050	Prepaid Taxes	APR-08	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$91,877.93	($34,668.42)	$57,209.51
14100	Other Prepaids		$197,795.55	($7,817.30)	$189,978.25
		Sum	$289,673.48	($42,485.72)	$247,187.76
14100	Other Prepaids	MAY-08	$189,978.25	($7,817.30)	$182,160.95
14010	Prepaid Insurance		$57,209.51	($34,668.42)	$22,541.09
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$247,187.76	($42,485.72)	$204,702.04
14050	Prepaid Taxes	JUN-08	$0.00	$105.59	$105.59
14010	Prepaid Insurance		$22,541.09	$189,018.71	$211,559.80
14100	Other Prepaids		$182,160.95	($136,933.05)	$45,227.90
		Sum	$204,702.04	$52,191.25	$256,893.29
14100	Other Prepaids	Jul-08	$45,227.90	($7,817.30)	$37,410.60
14010	Prepaid Insurance		$211,559.80	$198,230.35	$409,790.15
14050	Prepaid Taxes		$105.59	($105.59)	$0.00
		Sum	$256,893.29	$190,307.46	$447,200.75
14050	Prepaid Taxes	Aug-08	$0.00	$0.00	$0.00
14010	Prepaid Insurance		$409,790.15	($37,253.65)	$372,536.50
14100	Other Prepaids		$37,410.60	($11,644.71)	$25,765.89
		Sum	$447,200.75	($48,898.36)	$398,302.39
14100	Other Prepaids	Sep-08	$25,765.89	$24,366.60	$50,132.49
14010	Prepaid Insurance		$372,536.50	($65,002.17)	$307,534.33
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$398,302.39	($40,635.57)	$357,666.82
14100	Other Prepaids	Oct-08	$50,132.49	($3,989.92)	$46,142.57
14010	Prepaid Insurance		$307,534.33	($34,170.49)	$273,363.84
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$357,666.82	($38,160.41)	$319,506.41
14100	Other Prepaids	Nov-08	$46,142.57	($3,989.92)	$42,152.65
14010	Prepaid Insurance		$273,363.84	($34,170.49)	$239,193.35
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$319,506.41	($38,160.41)	$281,346.00
14100	Other Prepaids	Dec-08	$42,152.65	$66,032.50	$108,185.15
14010	Prepaid Insurance		$239,193.35	($34,170.49)	$205,022.86
14050	Prepaid Taxes		$0.00	$0.00	$0.00
		Sum	$281,346.00	$31,862.01	$313,208.01

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28a - Materials and Supplies 60 months ending December 2008

JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
12600	Undistributed Stores Expense		$198,298.59	($7,690.41)	$190,608.18
		Sum	$2,109,546.75	$68,040.53	$2,177,587.28
12500	Materials & Supplies	May-07	$1,986,979.10	($109,031.73)	$1,877,947.37
12600	Undistributed Stores Expense		$190,608.18	$35,535.22	$226,143.40
		Sum	$2,177,587.28	($73,496.51)	$2,104,090.77
12500	Materials & Supplies	Jun-07	$1,877,947.37	$25,843.86	$1,903,791.23
12600	Undistributed Stores Expense		$226,143.40	$5,881.03	$232,024.43
		Sum	$2,104,090.77	$31,724.89	$2,135,815.66
12500	Materials & Supplies	Jul-07	$1,903,791.23	$10,661.45	$1,914,452.68
12600	Undistributed Stores Expense		$232,024.43	$7,979.79	$240,004.22
		Sum	$2,135,815.66	$18,641.24	$2,154,456.90
12500	Materials & Supplies	Aug-07	$1,914,452.68	($104,471.06)	$1,809,981.62
12600	Undistributed Stores Expense		$240,004.22	$2,840.25	$242,844.47
		Sum	$2,154,456.90	($101,630.81)	$2,052,826.09
12500	Materials & Supplies	Sep-07	$1,809,981.62	($12,009.72)	$1,797,971.90
12600	Undistributed Stores Expense		$242,844.47	($317.12)	$242,527.35
		Sum	$2,052,826.09	($12,326.84)	$2,040,499.25
12500	Materials & Supplies	Oct-07	$1,797,971.90	($68,994.55)	$1,728,977.35
12600	Undistributed Stores Expense		$242,527.35	($6,458.67)	$236,068.68
		Sum	$2,040,499.25	($75,453.22)	$1,965,046.03
12500	Materials & Supplies	Nov-07	$1,728,977.35	($7,937.96)	$1,721,039.39
12600	Undistributed Stores Expense		$236,068.68	($9,964.26)	$226,104.42
		Sum	$1,965,046.03	($17,902.22)	$1,947,143.81
12500	Materials & Supplies	Dec-07	$1,721,039.39	$61,997.97	$1,783,037.36
12600	Undistributed Stores Expense		$226,104.42	$13,299.53	$239,403.95
		Sum	$1,947,143.81	$75,297.50	$2,022,441.31
12500	Materials & Supplies	Jan-08	$1,783,037.36	($17,700.82)	$1,765,336.54
12600	Undistributed Stores Expense		$239,403.95	$3,259.90	$242,663.85
		Sum	$2,022,441.31	($14,440.92)	$2,008,000.39
12500	Materials & Supplies	Feb-08	$1,765,336.54	($43,779.16)	$1,721,557.38
12600	Undistributed Stores Expense		$242,663.85	$33,280.37	$275,944.22
		Sum	$2,008,000.39	($10,498.79)	$1,997,501.60
12500	Materials & Supplies	Mar-08	$1,721,557.38	($55,802.04)	$1,665,755.34
12600	Undistributed Stores Expense		$275,944.22	$23,627.52	$299,571.74
		Sum	$1,997,501.60	($32,174.52)	$1,965,327.08
12500	Materials & Supplies	Apr-08	$1,665,755.34	($57,412.97)	$1,608,342.37
12600	Undistributed Stores Expense		$299,571.74	$2,848.01	$302,419.75
		Sum	$1,965,327.08	($54,564.96)	$1,910,762.12
12500	Materials & Supplies	May-08	$1,608,342.37	$32,977.77	$1,641,320.14
12600	Undistributed Stores Expense		$302,419.75	($13,365.08)	$289,054.67
		Sum	$1,910,762.12	$19,612.69	$1,930,374.81
12500	Materials & Supplies	Jun-08	$1,641,320.14	$27,285.13	$1,668,605.27
12600	Undistributed Stores Expense		$289,054.67	$52,400.46	$341,455.13
		Sum	$1,930,374.81	$79,685.59	$2,010,060.40
12500	Materials & Supplies	Jul-08	$1,668,605.27	($35,747.57)	$1,632,857.70
12600	Undistributed Stores Expense		$341,455.13	$3,565.13	$345,020.26

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28a - Materials and Supplies 60 months ending December 2008

JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	Beg Balance	Period Net	Balance
		Sum	$2,010,060.40	($32,182.44)	$1,977,877.96
12600	Undistributed Stores Expense	Aug-08	$345,020.26	$25,047.83	$370,068.09
12500	Materials & Supplies		$1,632,857.70	$1,621.59	$1,634,479.29
		Sum	$1,977,877.96	$26,669.42	$2,004,547.38
12500	Materials & Supplies	Sep-08	$1,634,479.29	($38,540.10)	$1,595,939.19
12600	Undistributed Stores Expense		$370,068.09	$5,853.54	$375,921.63
		Sum	$2,004,547.38	($32,686.56)	$1,971,860.82
12500	Materials & Supplies	Oct-08	$1,595,939.19	($6,154.34)	$1,589,784.85
12600	Undistributed Stores Expense		$375,921.63	$35,781.53	$411,703.16
		Sum	$1,971,860.82	$29,627.19	$2,001,488.01
12500	Materials & Supplies	Nov-08	$1,589,784.85	($13,552.05)	$1,576,232.80
12600	Undistributed Stores Expense		$411,703.16	$23,650.29	$435,353.45
		Sum	$2,001,488.01	$10,098.24	$2,011,586.25
12500	Materials & Supplies	Dec-08	$1,576,232.80	$31,381.20	$1,607,614.00
12600	Undistributed Stores Expense		$435,353.45	$76,313.41	$511,666.86
		Sum	$2,011,586.25	$107,694.61	$2,119,280.86

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28c. Customer Deposits

JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	End Balance
24100	Customer Deposits	JAN-06	($3,127,197.92)
24100	Customer Deposits	FEB-06	($3,126,339.75)
24100	Customer Deposits	MAR-06	($3,125,270.17)
24100	Customer Deposits	APR-06	($3,110,409.09)
24100	Customer Deposits	MAY-06	($3,096,040.90)
24100	Customer Deposits	JUN-06	($3,085,705.60)
24100	Customer Deposits	JUL-06	($3,093,543.92)
24100	Customer Deposits	AUG-06	($3,124,148.28)
24100	Customer Deposits	SEP-06	($3,200,738.94)
24100	Customer Deposits	OCT-06	($3,253,291.68)
24100	Customer Deposits	NOV-06	($3,346,209.35)
24100	Customer Deposits	DEC-06	($3,363,759.99)
24100	Customer Deposits	JAN-07	($3,402,069.30)
24100	Customer Deposits	FEB-07	($3,453,034.24)
24100	Customer Deposits	MAR-07	($3,426,840.79)
24100	Customer Deposits	APR-07	($3,514,869.51)
24100	Customer Deposits	MAY-07	($3,361,558.38)
24100	Customer Deposits	JUN-07	($3,365,274.14)
24100	Customer Deposits	JUL-07	($3,385,228.58)
24100	Customer Deposits	AUG-07	($3,386,825.41)
24100	Customer Deposits	OCT-07	($3,235,273.10)
24100	Customer Deposits	NOV-07	($3,184,534.59)
24100	Customer Deposits	DEC-07	($3,090,471.39)
24100	Customer Deposits	JAN-08	($3,028,603.93)
24100	Customer Deposits	FEB-08	($2,905,315.77)
24100	Customer Deposits	MAR-08	($2,804,224.92)
24100	Customer Deposits	APR-08	($2,737,549.95)
24100	Customer Deposits	MAY-08	($2,676,263.89)
24100	Customer Deposits	JUN-08	($2,609,271.06)
24100	Customer Deposits	JUL-08	($2,609,478.65)
24100	Customer Deposits	AUG-08	($2,611,299.02)
24100	Customer Deposits	SEP-08	($2,590,814.91)
24100	Customer Deposits	OCT-08	($2,589,543.17)
24100	Customer Deposits	NOV-08	($2,680,041.97)
24100	Customer Deposits	DEC-08	($2,687,432.88)

UNS GAS, INC.
STAFF'S 6TH SET: TF 6-28c. Customer Deposits

JANUARY 2006 THROUGH DECEMBER 2008
Note: January 2004 - December 2005 Provided in prior rate case.

Acct	Account Title	Date	End Balance
24100	Customer Deposits	JAN-06	($3,127,197.92)
24100	Customer Deposits	FEB-06	($3,126,339.75)
24100	Customer Deposits	MAR-06	($3,125,270.17)
24100	Customer Deposits	APR-06	($3,110,409.09)
24100	Customer Deposits	MAY-06	($3,096,040.90)
24100	Customer Deposits	JUN-06	($3,085,705.60)
24100	Customer Deposits	JUL-06	($3,093,543.92)
24100	Customer Deposits	AUG-06	($3,124,148.28)
24100	Customer Deposits	SEP-06	($3,200,738.94)
24100	Customer Deposits	OCT-06	($3,253,291.68)
24100	Customer Deposits	NOV-06	($3,346,209.35)
24100	Customer Deposits	DEC-06	($3,363,759.99)
24100	Customer Deposits	JAN-07	($3,402,069.30)
24100	Customer Deposits	FEB-07	($3,453,034.24)
24100	Customer Deposits	MAR-07	($3,426,840.79)
24100	Customer Deposits	APR-07	($3,514,869.51)
24100	Customer Deposits	MAY-07	($3,361,558.38)
24100	Customer Deposits	JUN-07	($3,365,274.14)
24100	Customer Deposits	JUL-07	($3,385,228.58)
24100	Customer Deposits	AUG-07	($3,386,825.41)
24100	Customer Deposits	OCT-07	($3,235,273.10)
24100	Customer Deposits	NOV-07	($3,184,534.59)
24100	Customer Deposits	DEC-07	($3,090,471.39)
24100	Customer Deposits	JAN-08	($3,028,603.93)
24100	Customer Deposits	FEB-08	($2,905,315.77)
24100	Customer Deposits	MAR-08	($2,804,224.92)
24100	Customer Deposits	APR-08	($2,737,549.95)
24100	Customer Deposits	MAY-08	($2,676,263.89)
24100	Customer Deposits	JUN-08	($2,609,271.06)
24100	Customer Deposits	JUL-08	($2,609,478.65)
24100	Customer Deposits	AUG-08	($2,611,299.02)
24100	Customer Deposits	SEP-08	($2,590,814.91)
24100	Customer Deposits	OCT-08	($2,589,543.17)
24100	Customer Deposits	NOV-08	($2,680,041.97)
24100	Customer Deposits	DEC-08	($2,687,432.88)

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 May 6, 2009

TF 6.64 List and describe all retirement and incentive programs available to Company officers and employees.

a. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

b. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE: Incentives: UNS Gas non-union employees participate in UniSource Energy Corporation's ("UniSource") Performance Enhancement Plan ("PEP"). Please see the PDF file TF 6.64(a) (Summary Performance Enhancement Plan), Bates Nos. UNSG(0571)07513 to UNSG(0571)07544, on the enclosed CD for the PEP plan description.

The structure determines eligibility for certain bonus levels by measuring UniSource's performance in three areas:

- Financial performance (UniSource's earnings per share);
- Operational cost containment (UniSource's utility O&M costs); and
- Core business and customer service goals

Levels of achievement in each area are assigned percentage-based "scores," and those scores are combined to calculate the final payout level. The amount made available for bonuses through this formula may range from 15 percent to 150 percent of the targeted payout level.

The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 3% to 14% for regular unclassified employees, and 25% to 80% for Managers and Officers. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion, based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Retirement Programs: UNS Gas Employees are eligible to participate in the Pension Plan for Employees of UniSource Energy Services ("UES"). Please see PDF file TF 6.63(c) (Pension Plan) in response to TF 6.63(c) for the summary plan description. Additionally, UNS Gas Employees are eligible to participate in the Tucson Electric Power Company ("TEP") 401(k) Plan as described below:

401(k) PLAN

TEP's 401(k) Plan takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 50% of their pay, before any deduction for state or federal income taxes. UniSource matches, 50 cents on the dollar, up to the first 6% of pay saved in the 401(k) Plan for UNS Gas employees.

Employees' savings and UniSource matching contributions are invested in one or any combination of a selection of professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. UniSource matching contributions are fully and immediately vested.

a. UNS Gas is in the process of gathering this information and will provide the response to this data request shortly.

b. UNS Gas is in the process of gathering this information and will provide the response to this data request shortly.

RESPONDENT: Gabrielle Camacho/Dawn Sabers

WITNESS: Dallas Dukes

SUPPLEMENTAL RESPONSE: a. & b. Please see the Excel workbook TF 6.64 on the enclosed CD for expenses for retirement plans requested. The allocation methodology is listed for each expense. For information on the allocation methodology, please see the response to TF 6.35 for our policies on allocations.

RESPONDENT: Linda Joyce

WITNESS: Karen Kissinger

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 May 6, 2009

SUPPLEMENTAL RESPONSE: The title of the PDF attachment listed above under the heading "Incentives" is listed incorrectly. The title of the attachment should be TF 6.64 (a) Pension Summary Plan Description. The Bates numbers for this file remain the same, Bates Nos. UNSG(0571)07513 to UNSG(0571)07544.

Additionally, please see the response to TF 6.92 for the Long-Term Incentive Program.

RESPONDENT: Gabrielle Camacho/Dawn Sabers

WITNESS: Dallas Dukes

UNS Gas, Inc.
Retirement & Incentive Plan Expense
For the Test Year Ended 6/30/08
In response to TF6.64a and 6.64b

Plan		Expense per UNSG G/L	Method of Allocation to UNSG
UES Plans:			
UES Pension Plan	$	705,104	Direct UNSG expense
UES 401K Plan	$	215,034	Direct UNSG expense
UES PEP Plan	$	271,655	Direct UNSG expense
Allocations from Other Plans:			
SERP Plan	$	101,021	Allocated Based on Massachusetts Formula
TEP PEP Plan	$	125,492	Allocated Based on Massachusetts Formula
Omnibus Plan	$	242,713	Allocated Based on Massachusetts Formula
Long-Term Incentive Plan	$	-	
Deferred Comp Plan	$	-	
	$	1,661,019	

SUMMARY PLAN DESCRIPTION OF THE PENSION PLAN FOR EMPLOYEES OF UNISOURCE ENERGY SERVICES

Effective August 11, 2003

Table of Contents

SUMMARY PLAN DESCRIPTION OF THE PENSION PLAN FOR EMPLOYEES OF UNISOURCE ENERGY SERVICES

Introduction

This document constitutes the Summary Plan Description ("SPD") for the Pension Plan for Employees of Unisource Energy Services (the "Plan"). The Plan is a defined benefit pension plan that Unisource Energy Services ("UES") has adopted for eligible employees. The Plan became effective as of August 11, 2003.

Few goals are of greater long-range importance than providing for a financially secure retirement. That is why Unisource Energy Services ("UES") sponsors this Plan for you and other eligible employees. The Plan is designed to provide you with retirement income for life based on your salary and the years you work for the UES or any other participating company ("Employer"). When your benefits under this Plan are combined with Social Security and your personal savings, it offers valuable financial security for your retirement years.

On August 11, 2003, Tucson Electric Power Company acquired certain assets and liabilities of Citizens Communications Company ("Citizens"). In connection with that acquisition, certain Citizens employees who were active participants in the Citizens Pension Plan became employees of UES. To the extent that those employees will also be entitled to benefits under this Plan, their benefits from this Plan will be integrated with the benefits provided from the Citizens Pension Plan.

Some terms in the summary are technical. See the Glossary in Appendix A starting at page 24 at the back of the SPD for the definition of any capitalized term you do not understand. If you still have questions, please call the Benefits Office for additional help.

You should read this summary closely so you understand how the Plan works. However, because this is a summary, not every provision is described and the description of certain provisions has been simplified. Full details are contained in the Plan document, which is a legal text governing the operation of the Plan. Copies of the Plan document are available to review in the Benefits Office during regular business hours. If you have any questions, contact the Plan Administrator. This SPD does not interpret, extend or change the Plan in any way. If there are any inconsistencies between this SPD and the Plan document, the provisions of the Plan document will govern your rights and benefits.

Eligibility and Enrollment

When Are You Eligible to Participate in this Plan?

Former Citizens Employees. If you were an active participant in the Citizens Pension Plan on August 10, 2003 -- the day before Citizens was acquired, you automatically became a Participant in this Plan as of August 11, 2003, if on that date or immediately after the end of a Permitted Leave, you (a) were employed by UES in an eligible class of Employees and (b) earned at least one "Hour of Service" (as defined below).

New Employees. You will become a Participant on the first day of the month on or after the day you become an Eligible Employee. You are an "Eligible Employee" if :

- UES has classified you as a common law employee of UES;
- you are at least age 21; and
- you have earned one year of Eligibility Service, which is a twelve-month period, beginning with your date of hire (or an anniversary of your date of hire) in which you are credited with at least 1,000 Hours of Service.

You are **not** in the class of employees eligible to participate in the Plan if:

- you provide services to UES as an independent contractor or consultant, or pursuant to an employee leasing agreement, or UES has classified you as a leased employee or as contract labor; or
- you are a collective bargaining employee, and your agreement does not specifically provide for your participation in the Plan; or
- you are a non-resident alien.

Defining Hours of Service. An Hour of Service is each hour that you actually work for UES or an affiliated employer. You also receive an Hour of Service for each regularly scheduled work hour that you do not work, but are paid or entitled to be paid due to an approved leave of absence, vacation, illness, jury duty, holiday or disability. However, you will not receive more than 501 hours of service for any single continuous period during which you perform no duties, and you cannot receive double credit for the same period of service.

Hours of Service are also credited for each hour for which back pay has either been paid, awarded or agreed to by a participating company (to the extent not already counted above).

If you are a former Citizens employee who was actively participating in the Citizens Pension Plan on August 10, 2003, your Hours of Service will include any hours credited to you under the terms of the Citizens Pension Plan, taking into account for this purpose the provisions relating to disregarding service due to a period of severance.

Rehired Employees. If you previously worked for UES and have been rehired as an Employee, your eligibility to participate in the Plan and the date you will be considered to be a Participant will depend on several factors, including (1) your years of employment with UES when you left; and (2) the length of time you were gone.

If you are not an Eligible Employee when you are rehired, you will become a Participant in accordance with the eligibility rules that apply for new Employees (described in the prior section).

If you are an Eligible Employee when you are rehired, you will become a Participant as follows:

- If you are gone for <u>less than 12 consecutive months</u>, you will become a Participant as of your date of rehire.

- If you are gone for <u>12 or more consecutive months</u>, you must earn at least one year of Eligibility Service after your rehire before you will become a Participant. Upon completing a year of Eligibility Service, you will become a Participant effective on your date of rehire.

- If you did not have a vested interest when you left employment and you are gone for <u>60 or more consecutive months</u>, you will be treated as a new Employee for purposes of reentering the Plan.

The rules regarding participation and credited service upon rehire are quite complex. If you think they may apply to you, please contact the Benefits Office for more detail.

Service with an affiliated employer. If you work for Tucson Electric Power Company or another affiliate which is part of the same corporate group as UES, you will continue to be credited with Hours of Service under the Plan. However, you will not be eligible to become a Participant unless you are employed by UES, and your service with the non-participating company will not count toward increasing your benefit.

Once You Are Eligible to Participate, How Do You Enroll?

Enrollment in the Plan is automatic. You do not have to complete an enrollment form in order to participate. UES's Benefit Office will notify you when you become a Participant in the Plan.

Who Pays For the Plan?

You do not have to contribute toward the cost of your pension benefits. UES contributes the funds to provide for the payment of benefits under the Plan, and those funds are held in trust.

Benefits Payable under the Plan

Plan Benefits At a Glance

The Plan Provides ...	When ...
Normal retirement benefit	At age 65.
Early retirement benefit	At age 55 if you have at least five years of Vesting Service.
Postponed retirement benefit	When you actually retire after age 65.
Benefits at termination of employment	After five years of Vesting Service.
Retirement income to your spouse	If you die after vesting but before benefits start.

Normal Retirement Benefit

You are eligible to retire with full benefits upon reaching your Normal Retirement Date. This is the first day of the month coinciding with or next following your 65th birthday. Your retirement benefit is calculated on the basis of the following:

- Your "Average Compensation,"
- Your "Average Covered Compensation," and
- Your years of "Benefit Service" up to 35 years.

Each of these terms is discussed below. In addition, if you were an active participant in the Citizens Pension Plan on August 10, 2003, and began participation in this Plan on August 11, 2003, your retirement benefit is reduced by the benefit payable to you from the Citizens Pension Plan. Here is the basic benefit formula that is used for calculating your normal retirement benefit when you retire on or after age 65:

Basic Benefit Formula at Normal Retirement Date
1.3% of your Average Compensation **PLUS** 0.7% of the excess of your Average Compensation over your Average Covered Compensation **MULTIPLIED BY** Your years of Benefit Service at retirement, up to 35 years **MINUS (for certain former Citizens employees)** The amount of benefit payable to you from the Citizens Pension Plan

For former Citizens employees who began participation in this Plan on August 11, 2003, note that your Average Compensation and Benefit Service with Citizens is counted in calculating your benefits. Your compensation and service with Citizens is determined according to the provisions of the Citizens Pension Plan (as in effect on August 10, 2003, or your earlier termination), and is counted even if your benefit was frozen as of February 1, 2003.

Here are the important terms you need to know to calculate your retirement benefit from the Plan:

Average Compensation. Your Average Compensation is your average monthly basic earnings for the 60 consecutive months of highest pay during the last 120 months of your Benefit Service. If you have less than 60 months of Benefit Service, Average Compensation will be based on the entire period of your service. For the purpose of determining whether months are consecutive, any month during which you have no Benefit Service will be ignored.

Here is an example. Assume your salary is set annually, so your monthly basic earnings are consistent throughout the year:

Year	Earnings	Year	Earnings
2001	$3,083.33	2006	$3,416.67*
2002	$3,166.67	2007	$3,750*
2003	$3,250	2008	$3,916.67*
2004	$3,583.33	2009	$4,083.33*
2005	$3,333.33*	2010 (6 months to 7/1)	$4,666.67*

*Your 60 consecutive months of highest pay are from July 1, 2005 through June 30, 2010. Your average monthly earnings are $3,833.

"Monthly basic earnings" means your monthly rate of base salary or wages paid to you, determined as of the first day of the month. If you are not compensated at a monthly rate, your monthly rate will be determined as 1/12th of your annual rate. Items of compensation other than base salary or wages, such as overtime pay, special remuneration and employer contributions to any employee benefit plan, are excluded from monthly basic earnings.

The following rules apply to the compensation used to determine Average Compensation:

- Compensation considered in any year cannot exceed $200,000. This amount changes based on IRS rules in effect from time to time.

- Compensation includes amounts you elect to have UES contribute on a pre-tax basis to a 401(k) plan, health plan or flexible spending account. However, non-qualified deferred compensation is not included.

Average Covered Compensation. This is the average of the annual Social Security wage bases on which you and your employer pay Social Security taxes during a 35-year period; it changes from year to year based on cost-of-living adjustments to the Social Security taxable wage base. This 35-year period ends on the last day of the calendar year in which you reach your Social Security retirement age. Average Covered Compensation is based on the Social Security law in effect on January 1, 1977.

Benefit Service. Your Benefit Service is all time (including any approved leaves of absence) beginning on the date you began working for UES and ending on your "Severance from Service" date. You have a "Severance from Service" when your employment terminates for any reason, including quit, involuntary termination, retirement or death. In addition, you have a Severance from Service on the first anniversary of a leave of absence, other than a leave due to (a) pregnancy, birth of a child, placement of a child with you in connection with adoption of the child or caring for a child immediately following birth or adoption or (b) any other protected leave under the Family and Medical Leave Act of 1993. You will have a Severance from Service no later than the second anniversary of the beginning of such a Medical or Family Leave (unless you earlier terminate due to quit, involuntary termination, etc.).

The following periods of service, however, are <u>not</u> included in your Benefit Service:

- any period before you became a Participant in the Plan;
- any Period of Severance, even if it is less than one year. A Period of Severance means the time beginning on your last day of work and ending on the date you are re-employed; and
- any period in which you are ineligible to participate in the Plan (for example, because you are employed by a non-participating affiliate).

If you are not Vested in your benefits when you leave employment or otherwise have a Severance from Service and are later rehired, you can lose credit for your prior Benefit Service. This will happen if:

- you have a period of severance of at least 60 consecutive months; or
- you have a period of severance of at least 12 consecutive months, and you do not earn at least 12 months of service after your reemployment with UES or an affiliated employer.

If you are a Part-Time Employee, your Benefit Service will be computed on the basis that 200 Hours of Service with UES is one-tenth (1/10) of a year of Benefit Service. However, no more than one year of Benefit Service will be credited in any Plan Year. "Part-Time Employee" means an employee who is employed and compensated for 28 hours per week or less.

If you were an active participant in the Citizens Pension Plan on August 10, 2003 and became a participant in this Plan on August 11, your Benefit Service will include the Benefit Service credited to you under the terms of the Citizens Pension Plan for purposes of calculating your benefit under the Plan , and the amount of offset of your benefit attributable to your Citizens Pension Plan benefit. Your Citizens' Benefit Service is also used in determining whether you have earned 35 years of Benefit Service. Note that Benefit Service that is disregarded under the Citizens Pension Plan because of a break in your service is similarly disregarded under this Plan.

An Example of the Normal Retirement Benefit Calculation – Assume you decide to retire in 2004 at age 65 with 30 years of Benefit Service. Also assume your Average Compensation is $4,200 per month. Based on your retirement date, your Annual Covered Compensation is $43,992, or $3,666 a month. Therefore, your Average Compensation over Average Covered Compensation is $534. Here's how your normal retirement benefit under this Plan is determined:

Normal Retirement Benefit Calculation Under this Plan

1.3% of your Average Compensation = .013 x $4,200 (A)	$54.60
Plus 0.7% of the excess of Average Compensation over Average Covered Compensation = .007 x $534 (B)	+ $3.74
Total of the two calculations above (A + B = C)	$58.34
Multiplied by the aggregate of your Benefit Service under the Citizens Pension Plan and this Plan (up to 35 years) (S)	x 30
Normal Straight Life retirement benefit (C x S) =	$1,750.20

In this example, your normal Retirement Benefit would be $1,750.20. This is the amount payable to you each month for life beginning at age 65. Keep in mind that your monthly payment will be adjusted if you elect to receive it in any other payment form - for example, in monthly payments over your lifetime and the lifetime of your spouse.

If you are a former Citizens employee who was an active participant in the Citizens Pension Plan on August 10, 2003 and began participation in this Plan on August 11, 2003, any amount payable to you under the Citizens Pension Plan will be subtracted from the amount payable under this Plan. For purposes of the prior example, assume that 29 of the 30 years of Benefit Service were with Citizens, and one year of Benefit Service was under this Plan. Also assume that your Average Compensation under the Prior Plan was $4,100, and Annual Covered Compensation was $3,664 in 2003. Therefore, your Average Compensation over Average Covered Compensation is $436.

Based on these assumptions, your normal Retirement Benefit under the Citizens Pension Plan would be:

$1,634.15 per month on a Straight Life basis. As a result, that amount will be deducted from the amount you will receive from this Plan. Accordingly, you will receive $1,634.15 per month from the Citizens Pension Plan and $116.05 per month from this Plan, for a total retirement benefit of $1,750.20 per month on a Straight Life basis.

Early Retirement Benefit

You may retire as early as the first day of the month coinciding with or next following your 55th birthday, as long as you have completed five years of Vesting Service. For the definition of Vesting Service, see the discussion entitled "How your Vesting Service is Determined," later in the SPD.

Your early Retirement Benefit is your Accrued Normal Retirement Benefit as of the date your employment ends, multiplied by the early retirement fraction described below. Your Accrued Normal Retirement Benefit is the benefit you have earned through the date you stop working (under the normal retirement formula above) but using the Benefit Service you would have had if you had continued working until your Normal Retirement Date (up to 35). This "projected" retirement benefit is then multiplied by the ratio of your actual Benefit Service to the Benefit Service you would have if you continued working to your Normal Retirement Date.

Formula for the Early Retirement Fraction

Your actual Benefit Service as of the date your employment terminates
(determined without regard to the 35 year limit)

DIVIDED BY

Your projected Benefit Service as if you had continued working until your Normal Retirement Date (determined without regard to the 35 year limit)

As noted above, your benefit will be subject to a second reduction if you begin receiving payments before your Normal Retirement Date. Your benefit will be reduced by five-twelfths (5/12) of one percent (1%) for each full month for which you receive distribution of your benefits before you turn age 65. This reduction is made because you will be receiving payments over a longer period of time. The reduction is calculated monthly; however, the schedule below gives you an idea of the reduction factors that would apply for selected ages:

Early Retirement Benefit Reduction Schedule

Age at Retirement	Reduction Factor (0.417% multiplied by pre-age 65 months)	Benefit as a % of Normal Retirement Benefit
65	0%	100%
64	5%	95%
63	10%	90%
62	15%	85%
61	20%	80%
60	25%	75%
59	30%	70%
58	35%	65%
57	40%	60%
56	45%	55%
55	50%	50%

If you retire in the middle of a year, the reduction is interpolated based on the first of the month in which your benefit begins.

An Example of the Early Retirement Benefit Calculation -- Assume as in the prior example that you decide to retire in 2004, but you are age 60 with 30 years of Benefit Service. Also assume your Average Compensation is the same, $4,200 per month. Based on your 2004 retirement date, your Annual Covered Compensation is $43,992, or $3,666 per month, and your Average Compensation over Average Covered Compensation is $534. Based on these assumptions, the early Retirement Benefit would be calculated as follows:

Early Retirement Benefit Calculation Under this Plan

1.3% of your Average Compensation = .013 x $4,200 (A)	$54.60
Plus 0.7% of the excess of Average Compensation over Average Covered Compensation = .007 x $534 (B)	+ $3.74
Total of the two calculations above (A + B = C)	$58.34
Multiplied by your Benefit Service projected to normal retirement date (up to 35 years) (S)	x 35
Normal straight life retirement benefit** (C x S) =	$2,041.90
Reduced by the Early Retirement Fraction of 30/35	x .857143
Monthly adjusted straight life benefit payable at age 65	$1,750.20

** Note that this amount will be reduced by amounts payable to you under the Citizens Pension Plan.

As you can see from the calculation, if you leave UES before your Normal Retirement Age, your early retirement benefit expressed as a straight life annuity benefit beginning at age 65 is $1,750.20. If you elect to receive payments before your 65th birthday, your benefit will be reduced by five-twelfths (5/12) of one percent (1%) for each month that you receive distribution of your benefits before you turn 65. In the example used above, if you elect to receive payments immediately after your 60th birthday, you will receive your benefits 60 months before your 65th birthday, so the reduction is 25%. Accordingly, you would receive 75% of $1,750.20, or $1,312.65 each month, commencing as of your 60th birthday. Also keep in mind that your monthly payment will be adjusted if you elect to receive it in any other payment form - for example, in monthly payments over your lifetime and the lifetime of your spouse.

Important: If you plan to retire early and you want to receive your benefits beginning with the first day of the month after your Termination of Employment, you should contact the Benefits Office at least 120 days in advance. Your retirement election must be made within the 90-day period ending on the date you want your retirement benefits to begin.

Postponed Retirement Benefit. You will continue to earn retirement benefits if you work beyond your Normal Retirement Date. In that case, you will receive a retirement benefit beginning on the first day of the month after you retire. Your postponed benefit is determined using the Normal Retirement Benefit formula above, based on your Average Compensation and Benefit Service (not in excess of 35 years) as of the date you retire.

Disability Retirement Benefit. If you are a Participant with five or more years of Vesting Service and you become Permanently Disabled while you are employed by UES, you will be entitled to a disability retirement benefit.

Definition of Permanent Disability and Disability Retirement Date

For purposes of this Plan, you will be considered to have a "Permanent Disability" (or be "Permanently Disabled") if you are determined to be disabled under the UES Long-Term Disability Plan ("LTD Plan"), and the disability continues for at least six (6) consecutive months.

Your Disability Retirement Date is the date that the Committee determines your absence due to the Permanent Disability began.

While you are Permanently Disabled, you will continue to be credited with Benefit Service and Vesting Service until the earliest of:

(1) the later of your Normal Retirement Date or the fifth anniversary of your Disability Retirement Date;

(2) the date you refuse to submit to a medical examination as required to determine whether the Permanent Disability still exists;

(3) the date you cease to be Permanently Disabled;

(4) the date of your death;

(5) the date your LTD Plan benefits cease; or

(6) the date your Retirement Benefit begins.

You can elect to begin your Retirement Benefits when you are eligible for a Normal or Early Retirement Benefit. Your disability retirement benefit will be calculated using the applicable benefit formula (based on whether you will be receiving an early or normal Retirement Benefit), based on your Average Compensation as of your Disability Retirement Date and the Benefit Service credited to you above. Remember that continuing service credits end when you elect to retire.

If you are a Part-Time Employee on your Disability Retirement Date, your Benefit Service will be credited at a rate of one-twentieth (1/20) of a year of Benefit Service for each month of Permanent Disability, with a maximum of six months of Benefit Service credited in any Plan Year.

Keep in mind that if you elect to receive a benefit before your Normal Retirement Age, the Plan's early retirement factors will apply.

Vesting and Forfeiture of Benefits at Termination of Employment

Vesting refers to the extent to which you have a nonforfeitable right to your retirement benefit when you leave UES. If you are credited with five or more Years of Vesting Service, your right to your retirement benefits are fully or 100% vested, and you are entitled to all of the benefits you earned under the Plan when you retire or otherwise leave UES. In addition, regardless of your Vesting Service, your benefits are 100% vested at your Normal Retirement Age if you are actively employed by UES.

How is Vesting Service Determined?

Vesting Service is equal to your aggregate Periods of Service and any periods that are required by law to be credited to you for periods of military service. A Period of Service begins on your Employment Commencement Date and ends on your Severance from Service Date, and includes Periods of Severance under 12 months. The following periods are not counted in determining Vesting Service:

- Any Periods of Severance of 12 months or more;
- Any Periods of Service before a Period of Severance that is 60 consecutive months or more, if benefits were not vested;
- Any Periods of Service before a Period of Severance of at least 12 consecutive months unless you are credited with a one year Period of Service after that Period of Severance; and
- Any Periods of Service prior to your 18th birthday.

A Period of Severance commences on the date your employment terminates, and ends on any subsequent reemployment date. A Period of Severance will not include:

- Credited Leave, which is defined as any leave of absence (1) due to illness or injury (not otherwise required to be credited to you under the Family and Medical Leave Act); or (2) for further education; or Government service as determined by UES;
- Any leave of absence to enter the Armed Forces of the United States (1) through the operation of a compulsory military service law; (2) during a period of declared national emergency; or (3) pursuant to a leave of absence granted by UES, as long as you return to the service of UES within 90 days (or such longer period as may be required by law) after your discharge or release from active duty, or within the period for which leave of absence was granted by UES; or
- Any absence from work due to a leave under the Family and Medical Leave Act.

If you began participation in this Plan or with an affiliated employer on August 11, 2003, your Vesting Service includes the Vesting Service credited to you under the terms of the Citizens Pension Plan, including its provisions disregarding service due to a Period of Severance.

Effect of Termination of Employment

If your employment terminates before your Early Retirement Age (age 55 with 5 or more years of Vesting Service), you will be entitled to receive benefits only if you have at least 5 years of Vesting Service when you leave. If you leave employment before you are fully vested in your benefits, you will forfeit your unvested pension benefits.

Your Termination of Employment Benefits are calculated in the same way as Early Retirement Benefits (described above), using your Benefit and Vesting Service as of the date of Termination of Employment. Your benefits can begin as early as the first of the month on or after your 55th birthday. Remember, benefits will be actuarially reduced if you begin payment before your Normal Retirement Date at a rate of 5/12^{ths} of 1% per month.

If the Actuarial Equivalent present value of your benefits when you leave is $5,000 or less, you will automatically receive your benefit in a single lump sum (which you may elect to have rolled over to a new plan). In contrast, if your benefits exceed $5,000, you will have a choice of the form in which you receive those benefits (see the section below entitled "How Benefits are Paid").

Be sure to notify UES if you have a change in address. This way, UES will be able to contact you when you become eligible for a distribution of your vested benefits.

Any benefit that is not vested will be deemed cashed out on the date you incur a Period of Severance of 12 consecutive months. If you are rehired and earn a Year of Service before you have a five (5) year Period of Severance, your benefit will be restored.

Transfers to Another Employer. If you transfer to an affiliated employer that has not adopted this Plan, you will cease to accrue additional benefits under this Plan.

Re-employment After Retirement.

If you are rehired by UES after you have begun receiving retirement benefits from this Plan before Normal Retirement Date (your sixty-fifth (65) birthday), your benefits will be suspended until you subsequently retire. When you subsequently retire, your benefit will be based upon your Average Compensation and Benefit Service at your subsequent retirement date, reduced by the actuarial value of prior payments you received. If you received a lump sum payment of your vested benefit when you previously left employment, your prior Benefit Service will be disregarded for all purposes of the Plan.

If you are rehired (or continue to be employed by UES) after your sixty-fifth (65th) birthday, your benefits will be suspended for each month in which you are credited with forty (40) or more Hours of Service. You must notify UES in order to resume benefits after you stop being so employed. Your benefits will resume no later than the third month after you stop being so employed, assuming you have given the required notice to UES.

The details regarding the impact of rehire upon the payment, the amount and form of benefits under the Plan are extensive. If you are thinking about returning to work with

UES after commencing your benefits under the Plan, please contact the Plan Administrator for the specific rules that will apply to your situation.

How Benefits are Paid

The Plan allows you to receive your retirement benefits in a variety of ways. You choose the method that best fits your personal financial needs.

Forms of Benefits. If the Actuarial Equivalent present value of your vested benefit exceeds $5,000, you may elect to receive your benefits under several different payment options:

- Life Annuity: This option provides monthly benefits to you for life. When you die, payments end. No income will be paid to anyone else.
- Life Annuity with a five or ten-year certain feature: The 5-year or 10-year life annuity pays reduced monthly benefits to you for life, with guaranteed payments for a period of 60 or 120 months, as you elect. If you die within the guaranteed period, your designated Beneficiary will receive your monthly benefit for the remainder of the period. If you receive monthly benefits for the full guaranteed period during your lifetime, no benefits will be paid after you die. The amount by which your benefit is reduced depends on the option you choose and your age. If your Beneficiary dies before you, you may designate a new Beneficiary.
- 33 1/3, 50%, 66 2/3%, 75%, or 100% Joint and Survivor Annuity Options: These options provide a reduced joint and survivor annuity. A joint and survivor annuity provides a monthly benefit to you for your lifetime. After your death, your Beneficiary will receive the percentage elected of your monthly benefit for the remainder of his or her lifetime. The monthly benefit you receive will be less than a single life annuity because it will be paid over two lifetimes - yours and your Beneficiary's. The amount of the reduction depends on your age and the age of your Beneficiary when benefit payments begin. If your Beneficiary dies before you, you cannot name another Beneficiary, and your payment level will not increase. Benefits end upon your death.
- Voluntary lump-sum distribution: If your vested benefit exceeds $5,000, this option provides a lump-sum distribution. The amount of the lump sum is the Actuarial Equivalent present value of your vested benefit payable on your Annuity Starting Date.

If the Actuarial Equivalent present value of your vested benefit is $5,000 or less, you will automatically receive your benefit in a single lump sum. This applies to both single and married employees. Thereafter, you will not be entitled to any monthly benefit.

Special Rules for Married Participants. If you are married on your Annuity Starting Date, you must receive distribution of your vested benefit in the form of a 50% (or greater) Joint and Survivor Annuity with your spouse as your Beneficiary, unless you and your spouse elect to waive this form of distribution. Your spouse's election must be witnessed by a notary public or the Plan Administrator during the 90-day period ending on your Annuity Starting Date. Your election must state the optional form of benefit that you would like distributed and the time of the distribution, and must designate any non-spouse Beneficiary, including contingent Beneficiaries, which cannot be changed without your spouse's consent (if applicable). A spouse's consent to the waiver, once given, may not be revoked. You may revoke the waiver of a Joint and Survivor Annuity without your spouse's consent at any time prior to your Annuity Starting Date (and if so desired, waive it again before that date so long as the requirements for the waiver are satisfied).

Electing a Payment Method. You must elect the form of payment during the 90-day period preceding your Annuity Starting Date. This election may not be changed after your Annuity Starting Date. Remember to contact us 120 days in advance. As you approach retirement age, you will receive more specific information about your benefit options and payment amounts.

If no election of method of distribution is made and you are single, you will be deemed to have elected a straight life annuity with no ancillary benefits. If you are married, you will be deemed to have selected a 50% Joint and Survivor Annuity with your spouse as the Beneficiary.

Keep in mind that you may be asked to provide copies of your birth certificate, applicable spouse birth certificate and marriage license, and may be asked to provide proof of a divorce or spouse death certificate.

Survivor Benefits

If You Die Before Retirement Benefits Begin. If you die before retirement benefits begin, have a vested benefit in the Plan, and are survived by a spouse to whom you have been married for at least one (1) year at the time of your death, your spouse will be eligible to receive a Qualified Preretirement Survivor Annuity. Your spouse is eligible for this benefit even if you are no longer working when you die. This benefit will be paid to your spouse in the form of an annuity for your spouse's life. If the Actuarial Equivalent present value of the Qualified Preretirement Survivor Annuity does not exceed $5,000, the benefit will be paid as a lump sum.

Amount of Benefit. The amount of the annuity your surviving spouse can receive from the plan is the survivor benefit the spouse would have received if you (1) terminated employment on your date of death or earlier termination date, (2) survived to your earliest retirement age under the plan (or, if later, your actual date of death), (3) elected a 50% Qualified Joint and Survivor Annuity at that time, and then (4) died immediately after you began receiving payments. Note that the benefit is actuarially adjusted to the extent that payments begin before you would have attained age of 65.

When Payments Begin. The distribution to your spouse will begin on the earliest of:

a) the first day of the month following your death, if your death occurs after your Normal Retirement Age;

b) the first day of the month following your Normal Retirement Age if your death occurs prior to that time, unless your spouse elects to receive the benefit before your Normal Retirement Age (but not earlier than the date you would have attained your Early Retirement Date had you survived); and

c) if you die before your Normal Retirement Age, and the Actuarial Equivalent present value of the Preretirement Death Benefit does not exceed $5,000, the first day of the month following your death.

If you die before your Normal Retirement Age, and the present value of your Preretirement Death Benefit exceeds $5,000, your spouse may elect to have distribution of the benefit begin on the first day of any month following the election, but not earlier than your Early Retirement Date or after your Normal Retirement Age.

Special Circumstances

- If you are married, and (a) you give the Committee written notice of your election to commence your retirement benefits on a specific date, or your retirement benefit is to commence on or after your Normal Retirement Date or after you reach age 70½ in the absence of such election, and (b) within 90 days prior to the benefit commencement date, you elect a joint and survivor annuity form of payment with your spouse to receive more than 50% of the amount payable, then your surviving spouse's annuity will be based on the larger amount payable under the joint and survivor annuity.

- If you are married, and (a) you die while employed or while on Permanent Disability after having elected to retire within 90 days of such election and to commence your retirement benefit in the form of a lump-sum payment, and (b) your death occurs prior to the benefit commencement date, a lump-sum payment in the same amount will be payable to your spouse on the date the payment would have been made to you had you lived. In order to receive this lump-sum payment, your spouse must, within 60 days after the date of your death, waive the Preretirement Death Benefit that would otherwise be payable.

If You Die After Retirement Benefits Begin. If you die after you have started to receive your retirement benefit, payments will continue only if you elected a payment form that provides for a survivor benefit to be paid to your designated Beneficiary. You need to understand that a single life annuity provides monthly benefits to you for life. If you elect to have your retirement benefit paid to you in that form, payments end when you die. No income will be paid to anyone else.

No benefit is paid under the plan if you die before retirement benefits begin and you are not survived by a legal spouse.

Taxes and Your Benefits

You are responsible for paying applicable taxes on your benefit when you receive it. Under current tax law, your retirement benefit is not taxable while it remains in the Plan. When you (or your Beneficiary) receive a distribution from the Plan, you are responsible for paying applicable income taxes. If a lump sum payment is made, you may also owe a 10% penalty tax if your retirement benefits are paid to you before age 59½ and you terminate employment before the beginning of the year in which you reach age 55.

In general, you can defer paying taxes if you elect to "rollover" your lump sum payout (that is, have it transferred directly) to a plan that will accept rollovers ("Eligible Retirement Plan"), such as a 401(k) plan, a section 457 government plan, or a section 403(b) annuity, or to a traditional or "conduit" individual retirement account ("IRA"). However, certain types of payments generally cannot be rolled over:

- Payments Spread Over Long Periods: Annuity payments cannot be rolled over because they are part of a series of equal (or almost equal) payments that are made at least once a year and will last for your lifetime or for more than ten (10) years.

- Required Minimum Payments: Beginning in the year you reach age 70½ or retire, whichever is later, a certain portion of your payment cannot be rolled over because it is a required minimum payment that must be paid to you.

If you do not elect a direct rollover of the entire lump sum distribution, the Plan is generally required to withhold 20% of the taxable portion of the amount distributed. You will receive additional information on the rollover or direct transfer option when you terminate employment and are ready to receive a distribution.

If you receive payment of your benefit in the form of an annuity (fixed payments for life), you may elect whether or not to have taxes withheld. If you do not make any election, federal income tax will be withheld automatically. Withholding is applied as if the payments were wages. If you elect not to have withholding apply, or even if you do elect withholding, you may still owe taxes on the payments. You are responsible for payment of any taxes associated with the payments.

Tax laws change from time to time, and the tax impact of receiving payments from the Plan will vary with your individual situation. Because UES cannot give tax advice or counsel, you should consult a professional tax advisor or financial expert for specific advice about your circumstances.

Social Security Benefits

Throughout your working career, both you and UES contribute toward your Social Security benefits through payroll taxes. These benefits are in addition to your benefits under the Plan and provide you with an important source of retirement income. ***You will not receive Social Security benefits automatically. You must apply for them.***

If you were born on or before January 1, 1938, your full Social Security benefits can begin at age 65. If you were born later than that date, your full Social Security benefits can begin between the ages of 65 and 67, depending on your birth date. You can consult the chart at the Social Security Administration's website on the Internet at http://www.ssa.gov/retirechartred.htm for the age when you will be entitled to receive your full benefits. You may begin receiving reduced Social Security benefits at age 62.

If you are married, your spouse also is entitled to receive Social Security benefits in an amount based on your pay or his or her pay – whichever produces the greater benefit.

Additional information about your Social Security benefits and how to apply for them is available through SSA's website at http://www.ssa.gov, or you can contact your local Social Security office. The national toll-free number for Social Security currently is 1-800-772-1213.

Plan Administration

The Plan is administered by a Committee appointed by the President of Tucson Electric Power Company. The Committee consists of at least three members, and its functions include resolving claims for benefits and interpreting and construing the terms of the Plan. The Committee has absolute and exclusive authority to interpret the provisions of the Plan in its discretion. The Committee will appoint a Plan Administrator who will maintain Plan records, and make appropriate reports and disclosures required by ERISA. A Trustee will be appointed to manage and control the trust fund and its assets.

How to Apply for Benefits -- Claims Procedure

To receive benefits under the Plan, you must apply to the Benefit Claims Committee. This section describes how to file a claim and an appeal.

Filing a Claim. There are specific procedures for filing claims and settling disputes. The Benefit Claims Committee can explain these to you. To receive benefits from the Plan, you or your Beneficiary must submit a request in writing to the Benefit Claims Committee. You should contact the Committee at least 90 days before you want to begin receiving your benefits.

If Your Claim is Wholly or Partially Denied. If you file a claim for benefits under the Plan and your claim is denied in whole or in part, you will be notified in writing. The notification will include:

- The reason for the denial;
- The specific Plan provisions on which the denial was based;
- A description of any additional information needed to process your claim; and
- An explanation of the claim review procedure.

Ordinarily you will receive this written notice within 30 days after your claim is filed.

If you disagree with the decision, you have a right to request a review of the denial of your claim. To do so, you, your Beneficiary, or your authorized representative must submit a written request to the Benefit Claims Committee within 60 days of receiving the notice of denial. You may review relevant documents or records and submit your comments in writing. You, your Beneficiary, or your authorized representative will have the right to review all pertinent Plan documents.

You will receive a written decision on your request for review within 60 days of the date the Benefit Claims Committee receives your request unless special circumstances, such as the need to hold a hearing, require an extension of time, in which case the 60-day period shall be extended to 120 days and you will be notified of the extension. You will be notified in writing of the final decision, and this decision shall include the specific reasons for the decision, referring to Plan provisions that set forth those reasons.

If you receive a final denial regarding your claim for benefits, you have certain rights under the law. For more information, see the section entitled "ERISA Rights" on page 21.

Additional Information About the Plan

The following is general information about the Plan, certain federal laws, and your rights under the Plan. Please read this section carefully, paying particular attention to how the Plan is governed by federal law.

Internal Revenue Service (IRS) Limits. Government regulations put a cap on the amount of income an employee may receive under a qualified pension plan. For example, Federal law limits the amount that can be considered as compensation for Plan purposes each year. In addition, the IRS sets certain limitations on the amount that employees can receive from plans like the Plan.

The IRS may adjust these limits from time to time to reflect changes in the cost of living. You will be notified if you are affected by these limits.

Non-assignment of Benefits and Qualified Domestic Relations Orders. You cannot assign the benefits payable to you to another person. One exception is that benefits will be paid according to a valid Qualified Domestic Relations Order (QDRO).

A QDRO is an order from a state court that meets certain legal specifications and directs the Plan to pay all or a portion of a Participant's benefits to a spouse, former spouse, or dependent child.

You will be notified immediately if an attempt is made to assign your benefits through a court order. The Committee is responsible for determining whether or not the order is qualified, and has adopted procedures governing QDROs. You can obtain a copy of those procedures, without charge, by contacting the Benefits Office.

Payment to Minors and Incompetents. If anyone entitled to income from the Plan is a minor or is judged to be physically or mentally incompetent, the Committee may pay the income to someone else for the benefit of the recipient (to a legal guardian, for example).

You may execute a form referred to as a "power of attorney" that authorizes another person or entity to act on your behalf if due to illness or incapacity, you are unable to do so yourself. You must specifically mention in the power of attorney that you are authorizing that person or entity to act on your behalf with regard to your benefits under this Plan. Please contact the Benefits Office for additional information regarding this issue.

Top-Heavy Rules. Under current tax law, if a plan provides more than 60% of its benefits to "key" employees, that plan is considered to be "top heavy." Both "top-heavy" and "key" employees are terms defined under the Code.

At present, the Plan is not top-heavy. In the unlikely event that it becomes top-heavy, you will be notified, your benefits may be adjusted, and your vesting may be accelerated to keep the Plan qualified under IRS regulations.

Continuance of the Plan

Amendment or Termination of the Plan. UES reserves the right to amend the Plan at any time and for any reason by action of the President of Tucson Electric Power Company ("TEP"). UES may also terminate the plan at any time and for any reason by action of the Board of Directors of TEP.

If UES terminates the plan for any reason, the assets in the Plan will be used for the exclusive benefit of Plan Participants and their beneficiaries. Any funds that remain after all benefits are paid to Participants will revert to UES. If you are affected by the termination, you will become 100% vested in your retirement benefit under the Plan, to the extent the benefit is funded.

Plan Insurance. The benefits under this Plan are insured by the Pension Benefit Guaranty Corporation ("PBGC"), a federal insurance agency. If the Plan terminates (ends) without enough money to pay all benefits, the PBGC will step in to administer the Plan and pay retirement benefits. Most people will receive all of the retirement benefits they would have received under the Plan, but some people may lose certain benefits.

The PBGC guarantee generally covers:

- Normal and Early retirement benefits;
- Disability benefits if you become disabled before the Plan terminates; and
- Certain benefits for your survivors.

The PBGC guarantee does not cover:

- Benefits greater than the maximum guarantee amount set by law for the year in which the Plan terminates;
- Some or all of benefit increases and new benefits based on Plan provisions that have been in place for fewer than 5 years at the time the Plan terminates;
- Benefits that are not vested because you have not worked long enough for UES;
- Benefits for which you have not met all of the requirements at the time the Plan terminates;
- Certain early retirement payments (such as supplemental benefits that stop when you become eligible for Social Security) that result in an early retirement monthly benefit greater than your monthly benefit at the plan's Normal Retirement Age; and
- Non-retirement benefits, such as health insurance, life insurance, certain death benefits, vacation pay and severance pay.

Even if some of your benefits are not guaranteed, you may still receive some of those benefits from the PBGC depending on how much money the Plan has and on how much the PBGC collects from employers. For more information on the PBGC and the benefits it guarantees, ask your Plan Administrator or contact the PBGC's Technical Assistance Division, 1200 K Street, N.W., Suite 930, Washington, D.C. 20005-4026 or call 202-326-4000 (not a toll-free number). TTY/TDD users may call the federal relay service toll-free at 1-800-877-8339 and ask to be connected to 202-326-4000. Additional information about the PBGC's pension insurance program is available through the PBGC's website on the Internet at http://www.pbgc.gov.

ERISA Rights

If you are a Participant in the Plan, you are entitled to certain rights and protections under the Employee Retirement Income Security Act of 1974 ("ERISA"). The following is a summary of those rights:

- You may examine, without charge, all Plan documents, including insurance contracts and copies of all documents filed by the Plan with the U.S. Department of Labor, such as detailed annual reports and Plan descriptions. These documents are available during regular business hours.

- You may obtain copies of all Plan documents by writing to the Plan Administrator. There will be a reasonable charge for duplicating documents.

- Each year you will receive a summary of the Plan's annual financial reports. The Plan Administrator is required by law to furnish you with a copy of this information.

- Upon your written request, you may obtain a statement telling whether you have a right to receive a benefit under the Plan, and if so, the amount of the benefit. If you are not eligible for a benefit, the statement will tell how many more years you have to work to get a right to a benefit. This statement is not required to be given more than once a year. It is provided free of charge.

- If your claim for a benefit is denied in whole or in part, you must receive a written explanation of the reason for the denial. You have the right to have the Plan review and reconsider the claim.

In addition to creating rights for Plan Participants, ERISA imposes duties on the people who are responsible for the operation of employee benefit plans. The people who operate the plan are called "fiduciaries." Fiduciaries have a duty to operate the plan prudently and in the interest of all Plan Participants and Beneficiaries. No one, including UES or any other person, may fire you or otherwise discriminate against you in any way to prevent you from obtaining a benefit or exercising your rights under ERISA.

Under ERISA, there are steps you can take to enforce these rights. For instance, if you make a written request for materials from the Plan and do not receive them within 30 days, you may file suit in federal court. In such a case, the court may require the Plan Administrator to provide the materials and pay you up to $110 a day until you receive the materials, unless the materials were not sent because of reasons beyond the control of the Plan Administrator. If you have a claim for benefits that is denied or ignored, in whole or in part, you may file suit in a state or federal court. In addition, if you disagree with the Plan's decision or lack thereof concerning the qualified status of a domestic relations order, you may file suit in a state or federal court.

If it should happen that the Plan fiduciaries misuse the Plan's money, or if you are discriminated against for asserting your rights, you may seek assistance from the U.S. Department of Labor, or you may file suit in a federal court. The court will decide who should pay court costs and legal fees. If you are successful, the court may order the person you have sued to pay these costs and legal fees. If you lose, the court may order you to pay these costs and fees; for example, if it finds that your claim is frivolous.

If you have any questions about the Plan, you should contact the Plan Administrator. If you have any questions about this statement or about your rights under ERISA, or if you need assistance in obtaining documents from the Plan Administrator, you should contact the nearest Area Office of the Employee Benefits Security Administration, U.S. Department of Labor, listed in your telephone directory or the Division of Technical Assistance and Inquiries, Employee Benefits Security Administration, U.S. Department of Labor, 200 Constitution Avenue, N.W., Washington, D.C. 20210.

Appendix A

Glossary of Terms

Actuarial Equivalent means a benefit or amount that replaces another and has the same value as the benefit or amount it replaces based on the applicable actuarial assumptions and interest rates.

Affiliated Company means UES or any entity that is in the same controlled group or under common control with UES in accordance with the rules defined in the Internal Revenue Code.

Annuity Starting Date generally means the first date as of which your vested retirement benefits or **Preretirement Death Benefits** are to begin, or the date on which your lump sum is paid to you.

Beneficiary means the person or persons who would become eligible to receive any benefits under the Plan in the event of your death.

Benefit Claims Committee means the committee designated to review your request for benefits.

Board means the Board of Directors of Tucson Electric Power Company or its authorized delegate.

Code means the Internal Revenue Code of 1986, as amended from time to time.

Committee means the committee appointed by the Board to administer the Plan.

Credited Leave means any leave of absence due to illness, injury, further education or Government service as determined by the **Committee**. This term includes any leave of absence to join the Armed Forces of the United States in connection with a compulsory military service law, during a period of declared national emergency, or if UES grants other military-related leaves of absence, provided you return to work within 90 days (or such longer periods as may be provided by law) after your discharge or release from active duty in the Armed Forces, or within the period for which your leave of absence was granted by UES.

Eligible Retirement Plan means an individual retirement account, individual retirement annuity, annuity plan, or qualified trust, as defined in the **Code**, that accepts your eligible rollover distribution. In the case of an eligible rollover distribution to a surviving spouse, an **Eligible Retirement Plan** is an individual retirement account or individual retirement annuity.

Employee means any person classified and treated by UES as a common-law employee.

Employer means **UES** and any participating company.

Employment Commencement Date generally means the day you are first credited with an **Hour of Service**, or if you had a **Period of Severance**, the day you are first credited with an **Hour of Service** after the **Period of Severance**.

ERISA is the Employee Retirement Income Security Act of 1974, as amended from time to time.

50% Joint and Survivor Annuity means an annuity for your lifetime with a survivor annuity for the life of your surviving spouse where the survivor annuity is 50% of the amount of the annuity payable during the joint lives of you and your spouse. The joint and survivor annuity is at least the **Actuarial Equivalent** of the most valuable form of benefit under the Plan payable to you on your **Annuity Starting Date**. Note, however, if you were participating in the Citizens Pension Plan on December 31, 1975, and if you were to die before receiving a total of 120 monthly payments, then your survivor will receive the amount that would have been payable to you (as though you had not died), until a total of 120 monthly payments have been made. After the 120th month, the amount of the survivor pension will be 50% of the reduced pension. In addition, the survivor annuity will be payable until a total of 120 monthly payments have been made without regard to whether or not your spouse is living. Any such survivor annuity payable after the death of your spouse will be payable to a **Beneficiary**.

Medical or Family Leave means an Employee's leave of absence from employment with an Affiliated Company because of: (a) pregnancy, birth of the Employee's child, placement of a child with the Employee in connection with adoption of the child or caring for a child immediately following birth or adoption or (b) any other reason that would entitle the Employee to take a leave under the Family and Medical Leave Act of 1993. The Employer shall determine the first and last day of any Medical or Family Leave.

Participant means an **Eligible Employee** who is participating in this Plan.

Period of Service means a period (including any periods of **Credited Leave**) beginning when a **Participant** is credited with an **Hour of Service (Employment Commencement Date)** and ending on the **Participant's Severance from Service Date**. For vesting purposes, **Period of Service** includes any **Period of Severance** under 12 months.

If you became a **Participant** in this **Plan** because you were an active participant in the Citizens Pension Plan on August 10, 2003, a **Period of Service** for any period prior to August 11, 2003, will be determined according to the terms of the **Citizens Pension Plan**, including provisions relating to disregarding service due to a **Period of Severance**.

Period of Severance means the time beginning on your last day of work and ending on the date you are re-employed.

Permanent Disability means total disability by bodily or mental injury or disease as determined by the Committee based on a determination made by the insurer under the Company's long-term disability plan or the Social Security Administration provided:

(a) the Employee has five years of Vesting Service;

(b) the Employee becomes entitled to benefits under the Company's long-term disability plan;

(c) the Employee earns at least one Hour of Service as an active Employee of an Employer after the Effective Date; and

(d) such disability shall have existed for a period of six consecutive calendar months.

Permitted Leave means an approved leave of absence from **UES,** including but not limited to military service, illness, disability, **Medical** or **Family Leave**, educational pursuits, service as a juror, temporary employment with a government agency, or any other leave of absence approved by the participating company.

Plan means the Pension Plan for Employees of Unisource Energy Services.

Plan Year means the calendar year.

Preretirement Death Benefit means the death benefit payable under the Plan to your surviving spouse if you die before your **Annuity Starting Date** and the following additional criteria are met:

- you have a vested benefit in the Plan, and
- you have been married to your spouse for at least one (1) year at the time of your death.

Qualified Preretirement Survivor Annuity means an immediate survivor annuity for the life of your spouse, equal to:

- If you die after your **Early Retirement Age**, the survivor annuity your spouse would have received if you had a **Termination of Employment** or Retirement on the day before your death and received distribution of benefits in the form of an immediate **50% Joint and Survivor Annuity**, or
- If you die on or before your **Early Retirement Age**, the survivor annuity your spouse would have received if you had a **Termination of Employment** on the day of your death, survived to your Early Retirement Date, received distribution of benefits in the form of a **50% Joint and Survivor Annuity** on your **Early Retirement Date**, and died on the day after your Early Retirement Date.

Retirement Benefit means the monthly benefit that you accrue under the Plan. The normal form of this benefit is a single life annuity. If you were a participant in the Citizens Pension Plan prior to January 1, 1976, the normal form of benefit is a single life annuity with a 10-year term certain.

Severance from Service Date means the earliest of:

- The day of your Retirement, **Termination of Employment**, or death,
- The second anniversary of your absence for Medical or Family Leave, and
- The first anniversary of the first day of a period in which you remain absent from service for any reason other than quitting, discharge, retirement or death.

If you incur a **Permanent Disability**, your Severance from Service Date will be the earliest of the following:

- The day on which you recover from the disability;

- Your 65^{th} birthday;
- The day you begin to receive distribution of your **Retirement Benefits**; or
- The day this Plan is terminated or the accrual of benefits under this Plan otherwise ceases.

Termination of Employment means the termination of your employment with UES, whether voluntary or involuntary, for any reason, including but not limited to, quit or discharge.

Vesting or **vested** means a right to receive a benefit that cannot be taken away from you. A **Vested benefit** means the nonforfeitable portion of your **Retirement Benefit**. You will become 100% **vested** after five (5) years of **Vesting Service.**

Vesting Service means your aggregate **Periods of Service** and any periods that are required by law to be credited to you for periods of military service. The following periods are not counted as **Vesting Service**:

- Any periods preceding a **Period of Severance** that is 60 consecutive months or more if you had no **Vested Interest;**
- Any periods preceding a **Period of Severance** of at least 12 consecutive months, unless you are credited with a **Period of Service** of one year after that **Period of Severance;**
- Any periods while your **Employer** is not **UES** or an affiliated employer; and
- **Periods of Service** prior to your 18^{th} birthday.

If you became a Participant in this Plan on August 11, 2003, and you were an active participant in the Citizens Pension Plan on August 10, 2003, your Vesting Service includes periods prior to August 11, 2003 credited to you under the terms of the Citizens Pension Plan, including its provisions disregarding service due to a period of severance.

A Final Word

As explained at the outset, this booklet provides a summary description of the Pension Plan for Employees of Unisource Energy Services. It highlights the main provisions of the Plan but is subject to the terms and provisions of the Plan Document. If this booklet and the official plan document vary in the description of the Plan, the plan document is the final authority.

This description of your pension benefits is not an employment contract or any type of employment guarantee.

GENERAL PLAN INFORMATION

Plan Name:	Pension Plan for Employees of Unisource Energy Services
Plan Sponsor and Address:	Tucson Electric Power Company 1 South Church Avenue, Suite 200 Tucson, AZ 85701
Employer Identification Number:	86-0062700
Plan Number:	003
Plan Administrator:	Pension Committee c/o Tucson Electric Power Company 1 South Church Avenue, Suite 200 Tucson, AZ 85701 Telephone (520) 571-4000 The Plan Administrator is designated as an agent for all purposes of legal process. Service of legal process may be made upon the Plan Administrator.
Type of Administration:	Committee appointed by Board of Directors of the Company.
Funding Medium:	Trust Fund
Trustee:	State Street Bank and Trust Company
Trustee's Address:	One Enterprise Drive North Quincy, MA 02171

SUMMARY PLAN DESCRIPTION OF THE PENSION PLAN FOR EMPLOYEES OF UNISOURCE ENERGY SERVICES

Effective August 11, 2003

Table of Contents

SUMMARY PLAN DESCRIPTION OF THE PENSION PLAN FOR EMPLOYEES OF UNISOURCE ENERGY SERVICES

Introduction

This document constitutes the Summary Plan Description ("SPD") for the Pension Plan for Employees of Unisource Energy Services (the "Plan"). The Plan is a defined benefit pension plan that Unisource Energy Services ("UES") has adopted for eligible employees. The Plan became effective as of August 11, 2003.

Few goals are of greater long-range importance than providing for a financially secure retirement. That is why Unisource Energy Services ("UES") sponsors this Plan for you and other eligible employees. The Plan is designed to provide you with retirement income for life based on your salary and the years you work for the UES or any other participating company ("Employer"). When your benefits under this Plan are combined with Social Security and your personal savings, it offers valuable financial security for your retirement years.

On August 11, 2003, Tucson Electric Power Company acquired certain assets and liabilities of Citizens Communications Company ("Citizens"). In connection with that acquisition, certain Citizens employees who were active participants in the Citizens Pension Plan became employees of UES. To the extent that those employees will also be entitled to benefits under this Plan, their benefits from this Plan will be integrated with the benefits provided from the Citizens Pension Plan.

Some terms in the summary are technical. See the Glossary in Appendix A starting at page 24 at the back of the SPD for the definition of any capitalized term you do not understand. If you still have questions, please call the Benefits Office for additional help.

You should read this summary closely so you understand how the Plan works. However, because this is a summary, not every provision is described and the description of certain provisions has been simplified. Full details are contained in the Plan document, which is a legal text governing the operation of the Plan. Copies of the Plan document are available to review in the Benefits Office during regular business hours. If you have any questions, contact the Plan Administrator. This SPD does not interpret, extend or change the Plan in any way. If there are any inconsistencies between this SPD and the Plan document, the provisions of the Plan document will govern your rights and benefits.

Eligibility and Enrollment

When Are You Eligible to Participate in this Plan?

Former Citizens Employees. If you were an active participant in the Citizens Pension Plan on August 10, 2003 -- the day before Citizens was acquired, you automatically became a Participant in this Plan as of August 11, 2003, if on that date or immediately after the end of a Permitted Leave, you (a) were employed by UES in an eligible class of Employees and (b) earned at least one "Hour of Service" (as defined below).

New Employees. You will become a Participant on the first day of the month on or after the day you become an Eligible Employee. You are an "Eligible Employee" if :

- UES has classified you as a common law employee of UES;
- you are at least age 21; and
- you have earned one year of Eligibility Service, which is a twelve-month period, beginning with your date of hire (or an anniversary of your date of hire) in which you are credited with at least 1,000 Hours of Service.

You are <u>**not**</u> in the class of employees eligible to participate in the Plan if:

- you provide services to UES as an independent contractor or consultant, or pursuant to an employee leasing agreement, or UES has classified you as a leased employee or as contract labor; or
- you are a collective bargaining employee, and your agreement does not specifically provide for your participation in the Plan; or
- you are a non-resident alien.

Defining Hours of Service. An Hour of Service is each hour that you actually work for UES or an affiliated employer. You also receive an Hour of Service for each regularly scheduled work hour that you do not work, but are paid or entitled to be paid due to an approved leave of absence, vacation, illness, jury duty, holiday or disability. However, you will not receive more than 501 hours of service for any single continuous period during which you perform no duties, and you cannot receive double credit for the same period of service.

Hours of Service are also credited for each hour for which back pay has either been paid, awarded or agreed to by a participating company (to the extent not already counted above).

If you are a former Citizens employee who was actively participating in the Citizens Pension Plan on August 10, 2003, your Hours of Service will include any hours credited to you under the terms of the Citizens Pension Plan, taking into account for this purpose the provisions relating to disregarding service due to a period of severance.

Rehired Employees. If you previously worked for UES and have been rehired as an Employee, your eligibility to participate in the Plan and the date you will be considered to be a Participant will depend on several factors, including (1) your years of employment with UES when you left; and (2) the length of time you were gone.

If you are not an Eligible Employee when you are rehired, you will become a Participant in accordance with the eligibility rules that apply for new Employees (described in the prior section).

If you are an Eligible Employee when you are rehired, you will become a Participant as follows:

- If you are gone for <u>less than 12 consecutive months</u>, you will become a Participant as of your date of rehire.

- If you are gone for <u>12 or more consecutive months</u>, you must earn at least one year of Eligibility Service after your rehire before you will become a Participant. Upon completing a year of Eligibility Service, you will become a Participant effective on your date of rehire.

- If you did not have a vested interest when you left employment and you are gone for <u>60 or more consecutive months</u>, you will be treated as a new Employee for purposes of reentering the Plan.

The rules regarding participation and credited service upon rehire are quite complex. If you think they may apply to you, please contact the Benefits Office for more detail.

Service with an affiliated employer. If you work for Tucson Electric Power Company or another affiliate which is part of the same corporate group as UES, you will continue to be credited with Hours of Service under the Plan. However, you will not be eligible to become a Participant unless you are employed by UES, and your service with the non-participating company will not count toward increasing your benefit.

Once You Are Eligible to Participate, How Do You Enroll?

Enrollment in the Plan is automatic. You do not have to complete an enrollment form in order to participate. UES's Benefit Office will notify you when you become a Participant in the Plan.

Who Pays For the Plan?

You do not have to contribute toward the cost of your pension benefits. UES contributes the funds to provide for the payment of benefits under the Plan, and those funds are held in trust.

Benefits Payable under the Plan

Plan Benefits At a Glance

The Plan Provides ...	When ...
Normal retirement benefit	At age 65.
Early retirement benefit	At age 55 if you have at least five years of Vesting Service.
Postponed retirement benefit	When you actually retire after age 65.
Benefits at termination of employment	After five years of Vesting Service.
Retirement income to your spouse	If you die after vesting but before benefits start.

Normal Retirement Benefit

You are eligible to retire with full benefits upon reaching your Normal Retirement Date. This is the first day of the month coinciding with or next following your 65th birthday. Your retirement benefit is calculated on the basis of the following:

- Your "Average Compensation,"
- Your "Average Covered Compensation," and
- Your years of "Benefit Service" up to 35 years.

Each of these terms is discussed below. In addition, if you were an active participant in the Citizens Pension Plan on August 10, 2003, and began participation in this Plan on August 11, 2003, your retirement benefit is reduced by the benefit payable to you from the Citizens Pension Plan. Here is the basic benefit formula that is used for calculating your normal retirement benefit when you retire on or after age 65:

Basic Benefit Formula at Normal Retirement Date
1.3% of your Average Compensation
PLUS
0.7% of the excess of your Average Compensation over your Average Covered Compensation
MULTIPLIED BY
Your years of Benefit Service at retirement, up to 35 years
MINUS (for certain former Citizens employees)
The amount of benefit payable to you from the Citizens Pension Plan

For former Citizens employees who began participation in this Plan on August 11, 2003, note that your Average Compensation and Benefit Service with Citizens is counted in calculating your benefits. Your compensation and service with Citizens is determined according to the provisions of the Citizens Pension Plan (as in effect on August 10, 2003, or your earlier termination), and is counted even if your benefit was frozen as of February 1, 2003.

Here are the important terms you need to know to calculate your retirement benefit from the Plan:

Average Compensation. Your Average Compensation is your average monthly basic earnings for the 60 consecutive months of highest pay during the last 120 months of your Benefit Service. If you have less than 60 months of Benefit Service, Average Compensation will be based on the entire period of your service. For the purpose of determining whether months are consecutive, any month during which you have no Benefit Service will be ignored.

Here is an example. Assume your salary is set annually, so your monthly basic earnings are consistent throughout the year:

Year	Earnings	Year	Earnings
2001	$3,083.33	2006	$3,416.67*
2002	$3,166.67	2007	$3,750*
2003	$3,250	2008	$3,916.67*
2004	$3,583.33	2009	$4,083.33*
2005	$3,333.33*	2010 (6 months to 7/1)	$4,666.67*

*Your 60 consecutive months of highest pay are from July 1, 2005 through June 30, 2010. Your average monthly earnings are $3,833.

"Monthly basic earnings" means your monthly rate of base salary or wages paid to you, determined as of the first day of the month. If you are not compensated at a monthly rate, your monthly rate will be determined as 1/12th of your annual rate. Items of compensation other than base salary or wages, such as overtime pay, special remuneration and employer contributions to any employee benefit plan, are excluded from monthly basic earnings.

The following rules apply to the compensation used to determine Average Compensation:

- Compensation considered in any year cannot exceed $200,000. This amount changes based on IRS rules in effect from time to time.
- Compensation includes amounts you elect to have UES contribute on a pre-tax basis to a 401(k) plan, health plan or flexible spending account. However, non-qualified deferred compensation is not included.

Average Covered Compensation. This is the average of the annual Social Security wage bases on which you and your employer pay Social Security taxes during a 35-year period; it changes from year to year based on cost-of-living adjustments to the Social Security taxable wage base. This 35-year period ends on the last day of the calendar year in which you reach your Social Security retirement age. Average Covered Compensation is based on the Social Security law in effect on January 1, 1977.

Benefit Service. Your Benefit Service is all time (including any approved leaves of absence) beginning on the date you began working for UES and ending on your "Severance from Service" date. You have a "Severance from Service" when your employment terminates for any reason, including quit, involuntary termination, retirement or death. In addition, you have a Severance from Service on the first anniversary of a leave of absence, other than a leave due to (a) pregnancy, birth of a child, placement of a child with you in connection with adoption of the child or caring for a child immediately following birth or adoption or (b) any other protected leave under the Family and Medical Leave Act of 1993. You will have a Severance from Service no later than the second anniversary of the beginning of such a Medical or Family Leave (unless you earlier terminate due to quit, involuntary termination, etc.).

The following periods of service, however, are <u>not</u> included in your Benefit Service:

- any period before you became a Participant in the Plan;
- any Period of Severance, even if it is less than one year. A Period of Severance means the time beginning on your last day of work and ending on the date you are re-employed; and
- any period in which you are ineligible to participate in the Plan (for example, because you are employed by a non-participating affiliate).

If you are not Vested in your benefits when you leave employment or otherwise have a Severance from Service and are later rehired, you can lose credit for your prior Benefit Service. This will happen if:

- you have a period of severance of at least 60 consecutive months; or
- you have a period of severance of at least 12 consecutive months, and you do not earn at least 12 months of service after your reemployment with UES or an affiliated employer.

If you are a Part-Time Employee, your Benefit Service will be computed on the basis that 200 Hours of Service with UES is one-tenth (1/10) of a year of Benefit Service. However, no more than one year of Benefit Service will be credited in any Plan Year. "Part-Time Employee" means an employee who is employed and compensated for 28 hours per week or less.

If you were an active participant in the Citizens Pension Plan on August 10, 2003 and became a participant in this Plan on August 11, your Benefit Service will include the Benefit Service credited to you under the terms of the Citizens Pension Plan for purposes of calculating your benefit under the Plan , and the amount of offset of your benefit attributable to your Citizens Pension Plan benefit. Your Citizens' Benefit Service is also used in determining whether you have earned 35 years of Benefit Service. Note that Benefit Service that is disregarded under the Citizens Pension Plan because of a break in your service is similarly disregarded under this Plan.

An Example of the Normal Retirement Benefit Calculation – Assume you decide to retire in 2004 at age 65 with 30 years of Benefit Service. Also assume your Average Compensation is $4,200 per month. Based on your retirement date, your Annual Covered Compensation is $43,992, or $3,666 a month. Therefore, your Average Compensation over Average Covered Compensation is $534. Here's how your normal retirement benefit under this Plan is determined:

Normal Retirement Benefit Calculation Under this Plan

1.3% of your Average Compensation = .013 x $4,200 (A)	$54.60
Plus 0.7% of the excess of Average Compensation over Average Covered Compensation = .007 x $534 (B)	+ $3.74
Total of the two calculations above (A + B = C)	$58.34
Multiplied by the aggregate of your Benefit Service under the Citizens Pension Plan and this Plan (up to 35 years) (S)	x 30
Normal Straight Life retirement benefit (C x S) =	$1,750.20

In this example, your normal Retirement Benefit would be $1,750.20. This is the amount payable to you each month for life beginning at age 65. Keep in mind that your monthly payment will be adjusted if you elect to receive it in any other payment form - for example, in monthly payments over your lifetime and the lifetime of your spouse.

If you are a former Citizens employee who was an active participant in the Citizens Pension Plan on August 10, 2003 and began participation in this Plan on August 11, 2003, any amount payable to you under the Citizens Pension Plan will be subtracted from the amount payable under this Plan. For purposes of the prior example, assume that 29 of the 30 years of Benefit Service were with Citizens, and one year of Benefit Service was under this Plan. Also assume that your Average Compensation under the Prior Plan was $4,100, and Annual Covered Compensation was $3,664 in 2003. Therefore, your Average Compensation over Average Covered Compensation is $436.

Based on these assumptions, your normal Retirement Benefit under the Citizens Pension Plan would be:

$1,634.15 per month on a Straight Life basis. As a result, that amount will be deducted from the amount you will receive from this Plan. Accordingly, you will receive $1,634.15 per month from the Citizens Pension Plan and $116.05 per month from this Plan, for a total retirement benefit of $1,750.20 per month on a Straight Life basis.

Early Retirement Benefit

You may retire as early as the first day of the month coinciding with or next following your 55th birthday, as long as you have completed five years of Vesting Service. For the definition of Vesting Service, see the discussion entitled "How your Vesting Service is Determined," later in the SPD.

Your early Retirement Benefit is your Accrued Normal Retirement Benefit as of the date your employment ends, multiplied by the early retirement fraction described below. Your Accrued Normal Retirement Benefit is the benefit you have earned through the date you stop working (under the normal retirement formula above) but using the Benefit Service you would have had if you had continued working until your Normal Retirement Date (up to 35). This "projected" retirement benefit is then multiplied by the ratio of your actual Benefit Service to the Benefit Service you would have if you continued working to your Normal Retirement Date.

Formula for the Early Retirement Fraction
Your actual Benefit Service as of the date your employment terminates (determined without regard to the 35 year limit) **DIVIDED BY** Your projected Benefit Service as if you had continued working until your Normal Retirement Date (determined without regard to the 35 year limit)

As noted above, your benefit will be subject to a second reduction if you begin receiving payments before your Normal Retirement Date. Your benefit will be reduced by five-twelfths (5/12) of one percent (1%) for each full month for which you receive distribution of your benefits before you turn age 65. This reduction is made because you will be receiving payments over a longer period of time. The reduction is calculated monthly; however, the schedule below gives you an idea of the reduction factors that would apply for selected ages:

Early Retirement Benefit Reduction Schedule

Age at Retirement	Reduction Factor (0.417% multiplied by pre-age 65 months)	Benefit as a % of Normal Retirement Benefit
65	0%	100%
64	5%	95%
63	10%	90%
62	15%	85%
61	20%	80%
60	25%	75%
59	30%	70%
58	35%	65%
57	40%	60%
56	45%	55%
55	50%	50%

If you retire in the middle of a year, the reduction is interpolated based on the first of the month in which your benefit begins.

An Example of the Early Retirement Benefit Calculation -- Assume as in the prior example that you decide to retire in 2004, but you are age 60 with 30 years of Benefit Service. Also assume your Average Compensation is the same, $4,200 per month. Based on your 2004 retirement date, your Annual Covered Compensation is $43,992, or $3,666 per month, and your Average Compensation over Average Covered Compensation is $534. Based on these assumptions, the early Retirement Benefit would be calculated as follows:

Early Retirement Benefit Calculation Under this Plan

1.3% of your Average Compensation = .013 x $4,200 (A)	$54.60
Plus 0.7% of the excess of Average Compensation over Average Covered Compensation = .007 x $534 (B)	+ $3.74
Total of the two calculations above (A + B = C)	$58.34
Multiplied by your Benefit Service projected to normal retirement date (up to 35 years) (S)	x 35
Normal straight life retirement benefit** (C x S) =	$2,041.90
Reduced by the Early Retirement Fraction of 30/35	x .857143
Monthly adjusted straight life benefit payable at age 65	$1,750.20

** Note that this amount will be reduced by amounts payable to you under the Citizens Pension Plan.

As you can see from the calculation, if you leave UES before your Normal Retirement Age, your early retirement benefit expressed as a straight life annuity benefit beginning at age 65 is $1,750.20. If you elect to receive payments before your 65th birthday, your benefit will be reduced by five-twelfths (5/12) of one percent (1%) for each month that you receive distribution of your benefits before you turn 65. In the example used above, if you elect to receive payments immediately after your 60th birthday, you will receive your benefits 60 months before your 65th birthday, so the reduction is 25%. Accordingly, you would receive 75% of $1,750.20, or $1,312.65 each month, commencing as of your 60th birthday. Also keep in mind that your monthly payment will be adjusted if you elect to receive it in any other payment form - for example, in monthly payments over your lifetime and the lifetime of your spouse.

Important: If you plan to retire early and you want to receive your benefits beginning with the first day of the month after your Termination of Employment, you should contact the Benefits Office at least 120 days in advance. Your retirement election must be made within the 90-day period ending on the date you want your retirement benefits to begin.

Postponed Retirement Benefit. You will continue to earn retirement benefits if you work beyond your Normal Retirement Date. In that case, you will receive a retirement benefit beginning on the first day of the month after you retire. Your postponed benefit is determined using the Normal Retirement Benefit formula above, based on your Average Compensation and Benefit Service (not in excess of 35 years) as of the date you retire.

Disability Retirement Benefit. If you are a Participant with five or more years of Vesting Service and you become Permanently Disabled while you are employed by UES, you will be entitled to a disability retirement benefit.

Definition of Permanent Disability and Disability Retirement Date

For purposes of this Plan, you will be considered to have a "Permanent Disability" (or be "Permanently Disabled") if you are determined to be disabled under the UES Long-Term Disability Plan ("LTD Plan"), and the disability continues for at least six (6) consecutive months.

Your Disability Retirement Date is the date that the Committee determines your absence due to the Permanent Disability began.

While you are Permanently Disabled, you will continue to be credited with Benefit Service and Vesting Service until the earliest of:

(1) the later of your Normal Retirement Date or the fifth anniversary of your Disability Retirement Date;

(2) the date you refuse to submit to a medical examination as required to determine whether the Permanent Disability still exists;

(3) the date you cease to be Permanently Disabled;

(4) the date of your death;

(5) the date your LTD Plan benefits cease; or

(6) the date your Retirement Benefit begins.

You can elect to begin your Retirement Benefits when you are eligible for a Normal or Early Retirement Benefit. Your disability retirement benefit will be calculated using the applicable benefit formula (based on whether you will be receiving an early or normal Retirement Benefit), based on your Average Compensation as of your Disability Retirement Date and the Benefit Service credited to you above. Remember that continuing service credits end when you elect to retire.

If you are a Part-Time Employee on your Disability Retirement Date, your Benefit Service will be credited at a rate of one-twentieth (1/20) of a year of Benefit Service for each month of Permanent Disability, with a maximum of six months of Benefit Service credited in any Plan Year.

Keep in mind that if you elect to receive a benefit before your Normal Retirement Age, the Plan's early retirement factors will apply.

Vesting and Forfeiture of Benefits at Termination of Employment

Vesting refers to the extent to which you have a nonforfeitable right to your retirement benefit when you leave UES. If you are credited with five or more Years of Vesting Service, your right to your retirement benefits are fully or 100% vested, and you are entitled to all of the benefits you earned under the Plan when you retire or otherwise leave UES. In addition, regardless of your Vesting Service, your benefits are 100% vested at your Normal Retirement Age if you are actively employed by UES.

How is Vesting Service Determined?

Vesting Service is equal to your aggregate Periods of Service and any periods that are required by law to be credited to you for periods of military service. A Period of Service begins on your Employment Commencement Date and ends on your Severance from Service Date, and includes Periods of Severance under 12 months. The following periods are not counted in determining Vesting Service:

- Any Periods of Severance of 12 months or more;
- Any Periods of Service before a Period of Severance that is 60 consecutive months or more, if benefits were not vested;
- Any Periods of Service before a Period of Severance of at least 12 consecutive months unless you are credited with a one year Period of Service after that Period of Severance; and
- Any Periods of Service prior to your 18^{th} birthday.

A Period of Severance commences on the date your employment terminates, and ends on any subsequent reemployment date. A Period of Severance will not include:

- Credited Leave, which is defined as any leave of absence (1) due to illness or injury (not otherwise required to be credited to you under the Family and Medical Leave Act); or (2) for further education; or Government service as determined by UES;
- Any leave of absence to enter the Armed Forces of the United States (1) through the operation of a compulsory military service law; (2) during a period of declared national emergency; or (3) pursuant to a leave of absence granted by UES, as long as you return to the service of UES within 90 days (or such longer period as may be required by law) after your discharge or release from active duty, or within the period for which leave of absence was granted by UES; or
- Any absence from work due to a leave under the Family and Medical Leave Act.

If you began participation in this Plan or with an affiliated employer on August 11, 2003, your Vesting Service includes the Vesting Service credited to you under the terms of the Citizens Pension Plan, including its provisions disregarding service due to a Period of Severance.

Effect of Termination of Employment

If your employment terminates before your Early Retirement Age (age 55 with 5 or more years of Vesting Service), you will be entitled to receive benefits only if you have at least 5 years of Vesting Service when you leave. If you leave employment before you are fully vested in your benefits, you will forfeit your unvested pension benefits.

Your Termination of Employment Benefits are calculated in the same way as Early Retirement Benefits (described above), using your Benefit and Vesting Service as of the date of Termination of Employment. Your benefits can begin as early as the first of the month on or after your 55th birthday. Remember, benefits will be actuarially reduced if you begin payment before your Normal Retirement Date at a rate of $5/12^{\text{ths}}$ of 1% per month.

If the Actuarial Equivalent present value of your benefits when you leave is $5,000 or less, you will automatically receive your benefit in a single lump sum (which you may elect to have rolled over to a new plan). In contrast, if your benefits exceed $5,000, you will have a choice of the form in which you receive those benefits (see the section below entitled "How Benefits are Paid").

Be sure to notify UES if you have a change in address. This way, UES will be able to contact you when you become eligible for a distribution of your vested benefits.

Any benefit that is not vested will be deemed cashed out on the date you incur a Period of Severance of 12 consecutive months. If you are rehired and earn a Year of Service before you have a five (5) year Period of Severance, your benefit will be restored.

Transfers to Another Employer. If you transfer to an affiliated employer that has not adopted this Plan, you will cease to accrue additional benefits under this Plan.

Re-employment After Retirement.

If you are rehired by UES after you have begun receiving retirement benefits from this Plan before Normal Retirement Date (your sixty-fifth (65) birthday), your benefits will be suspended until you subsequently retire. When you subsequently retire, *your benefit* will be based upon your Average Compensation and Benefit Service at your subsequent retirement date, reduced by the actuarial value of prior payments you received. If you received a lump sum payment of your vested benefit when you previously left employment, your prior Benefit Service will be disregarded for all purposes of the Plan.

If you are rehired (or continue to be employed by UES) after your sixty-fifth (65th) birthday, your benefits will be suspended for each month in which you are credited with forty (40) or more Hours of Service. You must notify UES in order to resume benefits after you stop being so employed. Your benefits will resume no later than the third month after you stop being so employed, assuming you have given the required notice to UES.

The details regarding the impact of rehire upon the payment, the amount and form of benefits under the Plan are extensive. If you are thinking about returning to work with

UES after commencing your benefits under the Plan, please contact the Plan Administrator *for the specific rules that will apply to your situation.*

How Benefits are Paid

The Plan allows you to receive your retirement benefits in a variety of ways. You choose the method that best fits your personal financial needs.

Forms of Benefits. If the Actuarial Equivalent present value of your vested benefit exceeds $5,000, you may elect to receive your benefits under several different payment options:

- Life Annuity: This option provides monthly benefits to you for life. When you die, payments end. No income will be paid to anyone else.

- Life Annuity with a five or ten-year certain feature: The 5-year or 10-year life annuity pays reduced monthly benefits to you for life, with guaranteed payments for a period of 60 or 120 months, as you elect. If you die within the guaranteed period, your designated Beneficiary will receive your monthly benefit for the remainder of the period. If you receive monthly benefits for the full guaranteed period during your lifetime, no benefits will be paid after you die. The amount by which your benefit is reduced depends on the option you choose and your age. If your Beneficiary dies before you, you may designate a new Beneficiary.

- 33 1/3, 50%, 66 2/3%, 75%, or 100% Joint and Survivor Annuity Options: These options provide a reduced joint and survivor annuity. A joint and survivor annuity provides a monthly benefit to you for your lifetime. After your death, your Beneficiary will receive the percentage elected of your monthly benefit for the remainder of his or her lifetime. The monthly benefit you receive will be less than a single life annuity because it will be paid over two lifetimes - yours and your Beneficiary's. The amount of the reduction depends on your age and the age of your Beneficiary when benefit payments begin. If your Beneficiary dies before you, you cannot name another Beneficiary, and your payment level will not increase. Benefits end upon your death.

- Voluntary lump-sum distribution: If your vested benefit exceeds $5,000, this option provides a lump-sum distribution. The amount of the lump sum is the Actuarial Equivalent present value of your vested benefit payable on your Annuity Starting Date.

If the Actuarial Equivalent present value of your vested benefit is $5,000 or less, you will automatically receive your benefit in a single lump sum. This applies to both single and married employees. Thereafter, you will not be entitled to any monthly benefit.

Special Rules for Married Participants. If you are married on your Annuity Starting Date, you must receive distribution of your vested benefit in the form of a 50% (or greater) Joint and Survivor Annuity with your spouse as your Beneficiary, unless you and your spouse elect to waive this form of distribution. Your spouse's election must be witnessed by a notary public or the Plan Administrator during the 90-day period ending on your Annuity Starting Date. Your election must state the optional form of benefit that you would like distributed and the time of the distribution, and must designate any non-spouse Beneficiary, including contingent Beneficiaries, which cannot be changed without your spouse's consent (if applicable). A spouse's consent to the waiver, once given, may not be revoked. You may revoke the waiver of a Joint and Survivor Annuity without your spouse's consent at any time prior to your Annuity Starting Date (and if so desired, waive it again before that date so long as the requirements for the waiver are satisfied).

Electing a Payment Method. You must elect the form of payment during the 90-day period preceding your Annuity Starting Date. This election may not be changed after your Annuity Starting Date. Remember to contact us 120 days in advance. As you approach retirement age, you will receive more specific information about your benefit options and payment amounts.

If no election of method of distribution is made and you are single, you will be deemed to have elected a straight life annuity with no ancillary benefits. If you are married, you will be deemed to have selected a 50% Joint and Survivor Annuity with your spouse as the Beneficiary.

Keep in mind that you may be asked to provide copies of your birth certificate, applicable spouse birth certificate and marriage license, and may be asked to provide proof of a divorce or spouse death certificate.

Survivor Benefits

If You Die Before Retirement Benefits Begin. If you die before retirement benefits begin, have a vested benefit in the Plan, and are survived by a spouse to whom you have been married for at least one (1) year at the time of your death, your spouse will be eligible to receive a Qualified Preretirement Survivor Annuity. Your spouse is eligible for this benefit even if you are no longer working when you die. This benefit will be paid to your spouse in the form of an annuity for your spouse's life. If the Actuarial Equivalent present value of the Qualified Preretirement Survivor Annuity does not exceed $5,000, the benefit will be paid as a lump sum.

Amount of Benefit. The amount of the annuity your surviving spouse can receive from the plan is the survivor benefit the spouse would have received if you (1) terminated employment on your date of death or earlier termination date, (2) survived to your earliest retirement age under the plan (or, if later, your actual date of death), (3) elected a 50% Qualified Joint and Survivor Annuity at that time, and then (4) died immediately after you began receiving payments. Note that the benefit is actuarially adjusted to the extent that payments begin before you would have attained age of 65.

When Payments Begin. The distribution to your spouse will begin on the earliest of:

a) the first day of the month following your death, if your death occurs after your Normal Retirement Age;

b) the first day of the month following your Normal Retirement Age if your death occurs prior to that time, unless your spouse elects to receive the benefit before your Normal Retirement Age (but not earlier than the date you would have attained your Early Retirement Date had you survived); and

c) if you die before your Normal Retirement Age, and the Actuarial Equivalent present value of the Preretirement Death Benefit does not exceed $5,000, the first day of the month following your death.

If you die before your Normal Retirement Age, and the present value of your Preretirement Death Benefit exceeds $5,000, your spouse may elect to have distribution of the benefit begin on the first day of any month following the election, but not earlier than your Early Retirement Date or after your Normal Retirement Age.

Special Circumstances

- If you are married, and (a) you give the Committee written notice of your election to commence your retirement benefits on a specific date, or your retirement benefit is to commence on or after your Normal Retirement Date or after you reach age 70½ in the absence of such election, and (b) within 90 days prior to the benefit commencement date, you elect a joint and survivor annuity form of payment with your spouse to receive more than 50% of the amount payable, then your surviving spouse's annuity will be based on the larger amount payable under the joint and survivor annuity.

- If you are married, and (a) you die while employed or while on Permanent Disability after having elected to retire within 90 days of such election and to commence your retirement benefit in the form of a lump-sum payment, and (b) your death occurs prior to the benefit commencement date, a lump-sum payment in the same amount will be payable to your spouse on the date the payment would have been made to you had you lived. In order to receive this lump-sum payment, your spouse must, within 60 days after the date of your death, waive the Preretirement Death Benefit that would otherwise be payable.

If You Die After Retirement Benefits Begin. If you die after you have started to receive your retirement benefit, payments will continue only if you elected a payment form that provides for a survivor benefit to be paid to your designated Beneficiary. You need to understand that a single life annuity provides monthly benefits to you for life. If you elect to have your retirement benefit paid to you in that form, payments end when you die. No income will be paid to anyone else.

No benefit is paid under the plan if you die before retirement benefits begin and you are not survived by a legal spouse.

Taxes and Your Benefits

You are responsible for paying applicable taxes on your benefit when you receive it. Under current tax law, your retirement benefit is not taxable while it remains in the Plan. When you (or your Beneficiary) receive a distribution from the Plan, you are responsible for paying applicable income taxes. If a lump sum payment is made, you may also owe a 10% penalty tax if your retirement benefits are paid to you before age 59½ and you terminate employment before the beginning of the year in which you reach age 55.

In general, you can defer paying taxes if you elect to "rollover" your lump sum payout (that is, have it transferred directly) to a plan that will accept rollovers ("Eligible Retirement Plan"), such as a 401(k) plan, a section 457 government plan, or a section 403(b) annuity, or to a traditional or "conduit" individual retirement account ("IRA"). However, certain types of payments generally cannot be rolled over:

- Payments Spread Over Long Periods: Annuity payments cannot be rolled over because they are part of a series of equal (or almost equal) payments that are made at least once a year and will last for your lifetime or for more than ten (10) years.

- Required Minimum Payments: Beginning in the year you reach age 70½ or retire, whichever is later, a certain portion of your payment cannot be rolled over because it is a required minimum payment that must be paid to you.

If you do not elect a direct rollover of the entire lump sum distribution, the Plan is generally required to withhold 20% of the taxable portion of the amount distributed. You will receive additional information on the rollover or direct transfer option when you terminate employment and are ready to receive a distribution.

If you receive payment of your benefit in the form of an annuity (fixed payments for life), you may elect whether or not to have taxes withheld. If you do not make any election, federal income tax will be withheld automatically. Withholding is applied as if the payments were wages. If you elect not to have withholding apply, or even if you do elect withholding, you may still owe taxes on the payments. You are responsible for payment of any taxes associated with the payments.

Tax laws change from time to time, and the tax impact of receiving payments from the Plan will vary with your individual situation. Because UES cannot give tax advice or counsel, you should consult a professional tax advisor or financial expert for specific advice about your circumstances.

Social Security Benefits

Throughout your working career, both you and UES contribute toward your Social Security benefits through payroll taxes. These benefits are in addition to your benefits under the Plan and provide you with an important source of retirement income. ***You will not receive Social Security benefits automatically. You must apply for them.***

If you were born on or before January 1, 1938, your full Social Security benefits can begin at age 65. If you were born later than that date, your full Social Security benefits can begin between the ages of 65 and 67, depending on your birth date. You can consult the chart at the Social Security Administration's website on the Internet at http://www.ssa.gov/retirechartred.htm for the age when you will be entitled to receive your full benefits. You may begin receiving reduced Social Security benefits at age 62.

If you are married, your spouse also is entitled to receive Social Security benefits in an amount based on your pay or his or her pay – whichever produces the greater benefit.

Additional information about your Social Security benefits and how to apply for them is available through SSA's website at http://www.ssa.gov, or you can contact your local Social Security office. The national toll-free number for Social Security currently is 1-800-772-1213.

Plan Administration

The Plan is administered by a Committee appointed by the President of Tucson Electric Power Company. The Committee consists of at least three members, and its functions include resolving claims for benefits and interpreting and construing the terms of the Plan. The Committee has absolute and exclusive authority to interpret the provisions of the Plan in its discretion. The Committee will appoint a Plan Administrator who will maintain Plan records, and make appropriate reports and disclosures required by ERISA. A Trustee will be appointed to manage and control the trust fund and its assets.

How to Apply for Benefits -- Claims Procedure

To receive benefits under the Plan, you must apply to the Benefit Claims Committee. This section describes how to file a claim and an appeal.

Filing a Claim. There are specific procedures for filing claims and settling disputes. The Benefit Claims Committee can explain these to you. To receive benefits from the Plan, you or your Beneficiary must submit a request in writing to the Benefit Claims Committee. You should contact the Committee at least 90 days before you want to begin receiving your benefits.

If Your Claim is Wholly or Partially Denied. If you file a claim for benefits under the Plan and your claim is denied in whole or in part, you will be notified in writing. The notification will include:

- The reason for the denial;
- The specific Plan provisions on which the denial was based;
- A description of any additional information needed to process your claim; and
- An explanation of the claim review procedure.

Ordinarily you will receive this written notice within 30 days after your claim is filed.

If you disagree with the decision, you have a right to request a review of the denial of your claim. To do so, you, your Beneficiary, or your authorized representative must submit a written request to the Benefit Claims Committee within 60 days of receiving the notice of denial. You may review relevant documents or records and submit your comments in writing. You, your Beneficiary, or your authorized representative will have the right to review all pertinent Plan documents.

You will receive a written decision on your request for review within 60 days of the date the Benefit Claims Committee receives your request unless special circumstances, such as the need to hold a hearing, require an extension of time, in which case the 60-day period shall be extended to 120 days and you will be notified of the extension. You will be notified in writing of the final decision, and this decision shall include the specific reasons for the decision, referring to Plan provisions that set forth those reasons.

If you receive a final denial regarding your claim for benefits, you have certain rights under the law. For more information, see the section entitled "ERISA Rights" on page 21.

Additional Information About the Plan

The following is general information about the Plan, certain federal laws, and your rights under the Plan. Please read this section carefully, paying particular attention to how the Plan is governed by federal law.

Internal Revenue Service (IRS) Limits. Government regulations put a cap on the amount of income an employee may receive under a qualified pension plan. For example, Federal law limits the amount that can be considered as compensation for Plan purposes each year. In addition, the IRS sets certain limitations on the amount that employees can receive from plans like the Plan.

The IRS may adjust these limits from time to time to reflect changes in the cost of living. You will be notified if you are affected by these limits.

Non-assignment of Benefits and Qualified Domestic Relations Orders. You cannot assign the benefits payable to you to another person. One exception is that benefits will be paid according to a valid Qualified Domestic Relations Order (QDRO).

A QDRO is an order from a state court that meets certain legal specifications and directs the Plan to pay all or a portion of a Participant's benefits to a spouse, former spouse, or dependent child.

You will be notified immediately if an attempt is made to assign your benefits through a court order. The Committee is responsible for determining whether or not the order is qualified, and has adopted procedures governing QDROs. You can obtain a copy of those procedures, without charge, by contacting the Benefits Office.

Payment to Minors and Incompetents. If anyone entitled to income from the Plan is a minor or is judged to be physically or mentally incompetent, the Committee may pay the income to someone else for the benefit of the recipient (to a legal guardian, for example).

You may execute a form referred to as a "power of attorney" that authorizes another person or entity to act on your behalf if due to illness or incapacity, you are unable to do so yourself. You must specifically mention in the power of attorney that you are authorizing that person or entity to act on your behalf with regard to your benefits under this Plan. Please contact the Benefits Office for additional information regarding this issue.

Top-Heavy Rules. Under current tax law, if a plan provides more than 60% of its benefits to "key" employees, that plan is considered to be "top heavy." Both "top-heavy" and "key" employees are terms defined under the Code.

At present, the Plan is not top-heavy. In the unlikely event that it becomes top-heavy, you will be notified, your benefits may be adjusted, and your vesting may be accelerated to keep the Plan qualified under IRS regulations.

Continuance of the Plan

Amendment or Termination of the Plan. UES reserves the right to amend the Plan at any time and for any reason by action of the President of Tucson Electric Power Company ("TEP"). UES may also terminate the plan at any time and for any reason by action of the Board of Directors of TEP.

If UES terminates the plan for any reason, the assets in the Plan will be used for the exclusive benefit of Plan Participants and their beneficiaries. Any funds that remain after all benefits are paid to Participants will revert to UES. If you are affected by the termination, you will become 100% vested in your retirement benefit under the Plan, to the extent the benefit is funded.

Plan Insurance. The benefits under this Plan are insured by the Pension Benefit Guaranty Corporation ("PBGC"), a federal insurance agency. If the Plan terminates (ends) without enough money to pay all benefits, the PBGC will step in to administer the Plan and pay retirement benefits. Most people will receive all of the retirement benefits they would have received under the Plan, but some people may lose certain benefits.

The PBGC guarantee generally covers:

- Normal and Early retirement benefits;
- Disability benefits if you become disabled before the Plan terminates; and
- Certain benefits for your survivors.

The PBGC guarantee does not cover:

- Benefits greater than the maximum guarantee amount set by law for the year in which the Plan terminates;
- Some or all of benefit increases and new benefits based on Plan provisions that have been in place for fewer than 5 years at the time the Plan terminates;
- Benefits that are not vested because you have not worked long enough for UES;
- Benefits for which you have not met all of the requirements at the time the Plan terminates;
- Certain early retirement payments (such as supplemental benefits that stop when you become eligible for Social Security) that result in an early retirement monthly benefit greater than your monthly benefit at the plan's Normal Retirement Age; and
- Non-retirement benefits, such as health insurance, life insurance, certain death benefits, vacation pay and severance pay.

Even if some of your benefits are not guaranteed, you may still receive some of those benefits from the PBGC depending on how much money the Plan has and on how much the PBGC collects from employers. For more information on the PBGC and the benefits it guarantees, ask your Plan Administrator or contact the PBGC's Technical Assistance Division, 1200 K Street, N.W., Suite 930, Washington, D.C. 20005-4026 or call 202-326-4000 (not a toll-free number). TTY/TDD users may call the federal relay service toll-free at 1-800-877-8339 and ask to be connected to 202-326-4000. Additional information about the PBGC's pension insurance program is available through the PBGC's website on the Internet at http://www.pbgc.gov.

ERISA Rights

If you are a Participant in the Plan, you are entitled to certain rights and protections under the Employee Retirement Income Security Act of 1974 ("ERISA"). The following is a summary of those rights:

- You may examine, without charge, all Plan documents, including insurance contracts and copies of all documents filed by the Plan with the U.S. Department of Labor, such as detailed annual reports and Plan descriptions. These documents are available during regular business hours.

- You may obtain copies of all Plan documents by writing to the Plan Administrator. There will be a reasonable charge for duplicating documents.

- Each year you will receive a summary of the Plan's annual financial reports. The Plan Administrator is required by law to furnish you with a copy of this information.

- Upon your written request, you may obtain a statement telling whether you have a right to receive a benefit under the Plan, and if so, the amount of the benefit. If you are not eligible for a benefit, the statement will tell how many more years you have to work to get a right to a benefit. This statement is not required to be given more than once a year. It is provided free of charge.

- If your claim for a benefit is denied in whole or in part, you must receive a written explanation of the reason for the denial. You have the right to have the Plan review and reconsider the claim.

In addition to creating rights for Plan Participants, ERISA imposes duties on the people who are responsible for the operation of employee benefit plans. The people who operate the plan are called "fiduciaries." Fiduciaries have a duty to operate the plan prudently and in the interest of all Plan Participants and Beneficiaries. No one, including UES or any other person, may fire you or otherwise discriminate against you in any way to prevent you from obtaining a benefit or exercising your rights under ERISA.

Under ERISA, there are steps you can take to enforce these rights. For instance, if you make a written request for materials from the Plan and do not receive them within 30 days, you may file suit in federal court. In such a case, the court may require the Plan Administrator to provide the materials and pay you up to $110 a day until you receive the materials, unless the materials were not sent because of reasons beyond the control of the Plan Administrator. If you have a claim for benefits that is denied or ignored, in whole or in part, you may file suit in a state or federal court. In addition, if you disagree with the Plan's decision or lack thereof concerning the qualified status of a domestic relations order, you may file suit in a state or federal court.

If it should happen that the Plan fiduciaries misuse the Plan's money, or if you are discriminated against for asserting your rights, you may seek assistance from the U.S. Department of Labor, or you may file suit in a federal court. The court will decide who should pay court costs and legal fees. If you are successful, the court may order the person you have sued to pay these costs and legal fees. If you lose, the court may order you to pay these costs and fees; for example, if it finds that your claim is frivolous.

If you have any questions about the Plan, you should contact the Plan Administrator. If you have any questions about this statement or about your rights under ERISA, or if you need assistance in obtaining documents from the Plan Administrator, you should contact the nearest Area Office of the Employee Benefits Security Administration, U.S. Department of Labor, listed in your telephone directory or the Division of Technical Assistance and Inquiries, Employee Benefits Security Administration, U.S. Department of Labor, 200 Constitution Avenue, N.W., Washington, D.C. 20210.

Appendix A

Glossary of Terms

Actuarial Equivalent means a benefit or amount that replaces another and has the same value as the benefit or amount it replaces based on the applicable actuarial assumptions and interest rates.

Affiliated Company means UES or any entity that is in the same controlled group or under common control with UES in accordance with the rules defined in the Internal Revenue Code.

Annuity Starting Date generally means the first date as of which your vested retirement benefits or **Preretirement Death Benefits** are to begin, or the date on which your lump sum is paid to you.

Beneficiary means the person or persons who would become eligible to receive any benefits under the Plan in the event of your death.

Benefit Claims Committee means the committee designated to review your request for benefits.

Board means the Board of Directors of Tucson Electric Power Company or its authorized delegate.

Code means the Internal Revenue Code of 1986, as amended from time to time.

Committee means the committee appointed by the Board to administer the Plan.

Credited Leave means any leave of absence due to illness, injury, further education or Government service as determined by the **Committee**. This term includes any leave of absence to join the Armed Forces of the United States in connection with a compulsory military service law, during a period of declared national emergency, or if UES grants other military-related leaves of absence, provided you return to work within 90 days (or such longer periods as may be provided by law) after your discharge or release from active duty in the Armed Forces, or within the period for which your leave of absence was granted by UES.

Eligible Retirement Plan means an individual retirement account, individual retirement annuity, annuity plan, or qualified trust, as defined in the **Code**, that accepts your eligible rollover distribution. In the case of an eligible rollover distribution to a surviving spouse, an **Eligible Retirement Plan** is an individual retirement account or individual retirement annuity.

Employee means any person classified and treated by UES as a common-law employee.

Employer means **UES** and any participating company.

Employment Commencement Date generally means the day you are first credited with an **Hour of Service**, or if you had a **Period of Severance**, the day you are first credited with an **Hour of Service** after the **Period of Severance**.

ERISA is the Employee Retirement Income Security Act of 1974, as amended from time to time.

50% Joint and Survivor Annuity means an annuity for your lifetime with a survivor annuity for the life of your surviving spouse where the survivor annuity is 50% of the amount of the annuity payable during the joint lives of you and your spouse. The joint and survivor annuity is at least the **Actuarial Equivalent** of the most valuable form of benefit under the Plan payable to you on your **Annuity Starting Date**. Note, however, if you were participating in the Citizens Pension Plan on December 31, 1975, and if you were to die before receiving a total of 120 monthly payments, then your survivor will receive the amount that would have been payable to you (as though you had not died), until a total of 120 monthly payments have been made. After the 120^{th} month, the amount of the survivor pension will be 50% of the reduced pension. In addition, the survivor annuity will be payable until a total of 120 monthly payments have been made without regard to whether or not your spouse is living. Any such survivor annuity payable after the death of your spouse will be payable to a **Beneficiary**.

Medical or Family Leave means an Employee's leave of absence from employment with an Affiliated Company because of: (a) pregnancy, birth of the Employee's child, placement of a child with the Employee in connection with adoption of the child or caring for a child immediately following birth or adoption or (b) any other reason that would entitle the Employee to take a leave under the Family and Medical Leave Act of 1993. The Employer shall determine the first and last day of any Medical or Family Leave.

Participant means an **Eligible Employee** who is participating in this Plan.

Period of Service means a period (including any periods of **Credited Leave**) beginning when a **Participant** is credited with an **Hour of Service (Employment Commencement Date)** and ending on the **Participant's Severance from Service Date**. For vesting purposes, **Period of Service** includes any **Period of Severance** under 12 months.

If you became a **Participant** in this **Plan** because you were an active participant in the Citizens Pension Plan on August 10, 2003, a **Period of Service** for any period prior to August 11, 2003, will be determined according to the terms of the **Citizens Pension Plan**, including provisions relating to disregarding service due to a **Period of Severance**.

Period of Severance means the time beginning on your last day of work and ending on the date you are re-employed.

Permanent Disability means total disability by bodily or mental injury or disease as determined by the Committee based on a determination made by the insurer under the Company's long-term disability plan or the Social Security Administration provided:

(a) the Employee has five years of Vesting Service;

(b) the Employee becomes entitled to benefits under the Company's long-term disability plan;

(c) the Employee earns at least one Hour of Service as an active Employee of an Employer after the Effective Date; and

(d) such disability shall have existed for a period of six consecutive calendar months.

Permitted Leave means an approved leave of absence from **UES,** including but not limited to military service, illness, disability, **Medical** or **Family Leave**, educational pursuits, service as a juror, temporary employment with a government agency, or any other leave of absence approved by the participating company.

Plan means the Pension Plan for Employees of Unisource Energy Services.

Plan Year means the calendar year.

Preretirement Death Benefit means the death benefit payable under the Plan to your surviving spouse if you die before your **Annuity Starting Date** and the following additional criteria are met:

- you have a vested benefit in the Plan, and
- you have been married to your spouse for at least one (1) year at the time of your death.

Qualified Preretirement Survivor Annuity means an immediate survivor annuity for the life of your spouse, equal to:

- If you die after your **Early Retirement Age**, the survivor annuity your spouse would have received if you had a **Termination of Employment** or Retirement on the day before your death and received distribution of benefits in the form of an immediate **50% Joint and Survivor Annuity**, or
- If you die on or before your **Early Retirement Age**, the survivor annuity your spouse would have received if you had a **Termination of Employment** on the day of your death, survived to your Early Retirement Date, received distribution of benefits in the form of a **50% Joint and Survivor Annuity** on your **Early Retirement Date,** and died on the day after your Early Retirement Date.

Retirement Benefit means the monthly benefit that you accrue under the Plan. The normal form of this benefit is a single life annuity. If you were a participant in the Citizens Pension Plan prior to January 1, 1976, the normal form of benefit is a single life annuity with a 10-year term certain.

Severance from Service Date means the earliest of:

- The day of your Retirement, **Termination of Employment**, or death,
- The second anniversary of your absence for Medical or Family Leave, and
- The first anniversary of the first day of a period in which you remain absent from service for any reason other than quitting, discharge, retirement or death.

If you incur a **Permanent Disability**, your Severance from Service Date will be the earliest of the following:

- The day on which you recover from the disability;

- Your 65^{th} birthday;
- The day you begin to receive distribution of your **Retirement Benefits**; or
- The day this Plan is terminated or the accrual of benefits under this Plan otherwise ceases.

Termination of Employment means the termination of your employment with UES, whether voluntary or involuntary, for any reason, including but not limited to, quit or discharge.

Vesting or **vested** means a right to receive a benefit that cannot be taken away from you. A **Vested benefit** means the nonforfeitable portion of your **Retirement Benefit**. You will become 100% **vested** after five (5) years of **Vesting Service.**

Vesting Service means your aggregate **Periods of Service** and any periods that are required by law to be credited to you for periods of military service. The following periods are not counted as **Vesting Service**:

- Any periods preceding a **Period of Severance** that is 60 consecutive months or more if you had no **Vested Interest**;
- Any periods preceding a **Period of Severance** of at least 12 consecutive months, unless you are credited with a **Period of Service** of one year after that **Period of Severance**;
- Any periods while your **Employer** is not **UES** or an affiliated employer; and
- **Periods of Service** prior to your 18^{th} birthday.

If you became a Participant in this Plan on August 11, 2003, and you were an active participant in the Citizens Pension Plan on August 10, 2003, your Vesting Service includes periods prior to August 11, 2003 credited to you under the terms of the Citizens Pension Plan, including its provisions disregarding service due to a period of severance.

A Final Word

As explained at the outset, this booklet provides a summary description of the Pension Plan for Employees of Unisource Energy Services. It highlights the main provisions of the Plan but is subject to the terms and provisions of the Plan Document. If this booklet and the official plan document vary in the description of the Plan, the plan document is the final authority.

This description of your pension benefits is not an employment contract or any type of employment guarantee.

GENERAL PLAN INFORMATION

Plan Name:	Pension Plan for Employees of Unisource Energy Services
Plan Sponsor and Address:	Tucson Electric Power Company 1 South Church Avenue, Suite 200 Tucson, AZ 85701
Employer Identification Number:	86-0062700
Plan Number:	003
Plan Administrator:	Pension Committee c/o Tucson Electric Power Company 1 South Church Avenue, Suite 200 Tucson, AZ 85701 Telephone (520) 571-4000 The Plan Administrator is designated as an agent for all purposes of legal process. Service of legal process may be made upon the Plan Administrator.
Type of Administration:	Committee appointed by Board of Directors of the Company.
Funding Medium:	Trust Fund
Trustee:	State Street Bank and Trust Company
Trustee's Address:	One Enterprise Drive North Quincy, MA 02171

UNS GAS, INC.'S RESPONSE TO
STAFF'S SIXTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
April 16, 2009

TF 6.103 Are there any aspects of the Company's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and policies established in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission orders, how the Company's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

RESPONSE: The only accounting adjustments that knowingly deviate from the Commission's prior decision for UNS Gas are: the "Customer Advances Adjustment" and the "Incentive Compensation Adjustment". The only known deviation within revenue requirements is the expense associated with "Supplemental Executive Retirement Plan."

In the prior Commission decision, 100% of the customer advances balance was deducted from rate base. The Company is requesting that the portion of the advances already expended by the end of the test year, but not included in rate base, be excluded from the advances credit to rate base. This is fully explained in the Direct Testimony of UNS Gas witness Mr. Dallas Dukes. The dollar and accounts impact can be found in the pro forma work papers provided in response to Commission Staff's data request JMK 1.1 workpapers supporting the adjustment.

In the prior Commission decision, 50% of the incentive compensation expense was excluded from revenue requirements. UNS Gas is requesting full recovery of the normal and recurring level of incentive compensations expense. This is fully explained in the Direct Testimony of UNS Gas witness Mr. Dallas Dukes. The dollar and accounts impact can be found in the pro forma work papers provided in response to Commission Staff's data request JMK 1.1 workpapers supporting the adjustment.

In the prior Commission decision 100% of the supplemental executive retirement plan expense was excluded from revenue requirements. UNS Gas is requesting full recovery of the normal and recurring level of the expense contained within the test year. The dollar and accounts impact are being provided in response to TF 6.64.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

UNS GAS, INC.'S SUPPLEMENTA RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 May 14, 2009

TF 6.92 Please provide complete copies of any bonus programs or incentive award programs in effect at the Company for the most recent three years. Identify all incentive and bonus program expense incurred in 2008 and 2009. Identify the accounts charged. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in 2008 and 2009.

RESPONSE: See response to TF 6.64 for description of bonus program available to UNS Gas Non-Union Employees. Union employees are not eligible for a bonus program.

Long-term Incentive Program: UNS Gas Officers are eligible to participate in a Long-term Incentive Program. Please see the PDF File TF 6.92 Officer LTI (Confidential), Bates Nos. UNSG(0571)07992 to UNSG(0571)07993 on the enclosed CD for descriptions of the terms of the 2008 long-term incentive program.

Bates Nos. UNSG(0571)07992 to UNSG(0571)07993 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

SUPPLEMENTAL RESPONSE: See response to TF 6.64 for description of bonus program available to UNS Gas Non-Union Employees. Union employees are not eligible for a bonus program.

Long-term Incentive Program: UNS Gas Officers are eligible to participate in a Long-term Incentive Program. Please see the PDF File provided in response to TF 6.92 on April 17, 2009, TF 6.92 Officer LTI (Confidential), Bates Nos. UNSG(0571)07992 to UNSG(0571)07993, for descriptions of the terms of the 2008 long-term incentive program.

Bates Nos. UNSG(0571)07992 to UNSG(0571)07993 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

Expense:

- UNS Gas Incentive Compensation ("PEP:) Program (excluding officers):
  2008 = $268,127.72
  Charged to Account 50100, Sub 0000, Expenditure Type 050, FERC 0870, 0874, 0880, 0887, 0920

**UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S SIXTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
May 14, 2009**

- UNS Gas Incentive Compensation (PEP) Program Officer portion of Incentive: Allocated by Massachusetts Formula

  2008 = $129,761.00

  Charged to Account 52100, Sub 0000, Expenditure Type 052, FERC 0920
- Stock Option Expense: Allocated by Massachusetts Formula

  2008 = $129,850.02

  Charged to Account 50100, Sub 4014, Expenditure Type 085, FERC 0920
- Dividend Equivalents on Stock Units: Allocated by Massachusetts Formula

  2008 = $18,780.67

  Charged to Account 50100, 79040, Sub 3604, Expenditure Type 085, FERC 0920
- Performance Share Award: Allocated by Massachusetts Formula

  2008 = $34,689.17

  Charged to Account 50100, Sub 4013, Expenditure Type 085, FERC 0920
- Dividend Equivalent on Stock Options: Allocated by Massachusetts Formula

  2008 = $23,806.64

  Charged to Account 50100, 79040, Sub 4019, Expenditure Type 085, FERC 0920
- Spot Awards

  2008 = $12,535.05

  Charged to Account 50100, Sub 0000, Expenditure Type 055, FERC 0920
- Directors Stock Awards: Allocated by Massachusetts Formula

  2008 = $72,263.73

  Charged to Account 79040, Sub 4020, Expenditure Type 230, FERC 0930

UNS Gas is unable to provide 2009 results until the quarterly reports have been filed with the SEC .

RESPONDENT: Maya Liddell

WITNESS: Dallas Dukes

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 May 14, 2009

SUPPLEMENTAL RESPONSE: The following items have been updated to reflect January 2009 through March 2009 data.

Expense (charged or allocated):

- UNS Gas Incentive Compensation ("PEP") Program (excluding officers):

  2009 = $63,000.00

  Charged to Account 50100, Sub 0000, Expenditure Type 050, FERC 0870, 0874, 0880, 0887, 0920

- UNS Gas Incentive Compensation ("PEP") Program Officer portion of Incentive: Allocated by Massachusetts Formula

  2009 = $28,749.00

  Charged to Account 52100, Sub 0000, Expenditure Type 052, FERC 0920

- Stock Option Expense: Allocated by Massachusetts Formula

  2009 = $35,936.79

  Charged to Account 50100, Sub 4014, Expenditure Type 085, FERC 0920

- Dividend Equivalents on Stock Units: Allocated by Massachusetts Formula

  2009 = $2,231.72

  Charged to Account 50100, 79040, Sub 3604, Expenditure Type 085, 230, FERC 0920

- Performance Share Award: Allocated by Massachusetts Formula

  2009 = $21,637.38

  Charged to Account 50100, Sub 4013, Expenditure Type 085, FERC 0920

- Dividend Equivalent on Stock Options: Allocated by Massachusetts Formula

  2009 = $2,811.89

  Charged to Account 50100, 79040, Sub 4019, Expenditure Type 085, 230, FERC 0920

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S SIXTH SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 May 14, 2009

- Spot Awards

  2009 = N/A

  Charged to Account 50100, Sub 0000, Expenditure Type 055, FERC 0920

- Directors Stock Awards: Allocated by Massachusetts Formula

  2009 = $16,334.99

  Charged to Account 79040, Sub 4020, Expenditure Type 230, FERC 0930

RESPONDENT: Gabrielle Camacho/Warner Jones

WITNESS: Dallas Dukes

UniSource Energy

One South Church Avenue
Tucson, Arizona 85701

March 23, 2009

(520) 571-4000

Paul J. Bonavia
Chairman of the Board

Dear Shareholders:

You are cordially invited to attend the UniSource Energy Corporation 2009 Annual Shareholders' Meeting (the "Meeting") to be held on Friday, May 8, 2009, at the FOX Theatre, 17 West Congress, Tucson, Arizona. The Meeting will begin promptly at 10:00 a.m., Mountain Standard Time, so please plan to arrive earlier. No admission tickets will be required for attendance at the Meeting.

Directors and officers will be available before and after the Meeting to speak with you. During the Meeting, we will answer your questions regarding our business affairs and we will consider the matters explained in the enclosed Proxy Statement.

We have enclosed a proxy card that lists all matters that require your vote. Please complete, sign, date and mail the proxy card as soon as possible, whether or not you plan to attend the Meeting. You may also vote by telephone or the Internet, as explained on the enclosed proxy card. If you attend the Meeting and wish to vote your shares personally, you may revoke your proxy at that time.

Your interest in and continued support of UniSource Energy Corporation are much appreciated.

Sincerely,

UNISOURCE ENERGY CORPORATION

Paul J. Bonavia
Chairman of the Board, President and
Chief Executive Officer

NOTICE OF ANNUAL SHAREHOLDERS' MEETING

**To the Holders of Common Stock of
UniSource Energy Corporation**

We will hold the 2009 Annual Shareholders' Meeting of UniSource Energy Corporation at the FOX Theatre, 17 West Congress, Tucson, Arizona, on Friday, May 8, 2009, at 10:00 a.m., Mountain Standard Time ("MST"). The purpose of the Meeting is to:

1. elect 14 directors to our Board of Directors for the ensuing year;
2. ratify the selection of the Independent Registered Public Accounting Firm for 2009; and
3. consider any other matters which properly come before the Meeting.

Only shareholders of record at the close of business on March 16, 2009, are entitled to vote at the Meeting.

We have enclosed with this notice: (i) our 2008 annual report on Form 10-K; (ii) the Proxy Statement; (iii) the Chairman's letter to shareholders; and (iv) a stock performance chart. Proxy soliciting material is first being made available in electronic form, on or about March 27, 2009. Your proxy is being solicited by our Board of Directors.

Please complete, sign, date and mail the enclosed proxy card as soon as possible, or vote by telephone or the Internet, as explained on the enclosed proxy card.

Linda Kennedy

Linda H. Kennedy
Corporate Secretary

Dated: March 23, 2009

YOUR VOTE IS IMPORTANT

EACH SHAREHOLDER IS URGED TO COMPLETE, SIGN, DATE AND RETURN PROMPTLY THE ENCLOSED PROXY CARD BY MAIL, OR TO VOTE BY TELEPHONE OR THE INTERNET, AS EXPLAINED ON THE ENCLOSED PROXY CARD. IF THE MAIL OPTION IS SELECTED, USE THE ENCLOSED ENVELOPE, WHICH DOES NOT REQUIRE POSTAGE IF MAILED IN THE UNITED STATES. RETURNING A SIGNED PROXY WILL NOT PROHIBIT YOU FROM ATTENDING THE MEETING AND VOTING IN PERSON IF YOU SO DESIRE.

UNISOURCE ENERGY CORPORATION

One South Church Avenue
Tucson, Arizona 85701

ANNUAL SHAREHOLDERS' MEETING
PROXY STATEMENT

ANNUAL MEETING:

May 8, 2009 10:00 a.m., MST	FOX Theatre 17 West Congress Tucson, AZ 85701

RECORD DATE:

The record date is March 16, 2009 ("Record Date"). If you were a shareholder of record at the close of business on the Record Date, you may vote at the 2009 Annual Shareholders' Meeting ("Meeting") of UniSource Energy Corporation ("UniSource Energy" as well as references to the "Company," "we," "our" and "us"). At the close of business on the Record Date, we had 35,610,300 shares of common stock outstanding.

AGENDA:

1. Proposal One: Elect 14 directors to our Board of Directors ("Board") for the ensuing year.
2. Proposal Two: Ratify the selection of the Independent Registered Public Accounting Firm for 2009.
3. Proposal Three: Consider any other matters which properly come before the Meeting and any adjournments.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM:

Representatives of PricewaterhouseCoopers, LLP are expected to be present at the Meeting with the opportunity to make a statement and respond to appropriate questions from our shareholders.

PROXIES:

In accordance with rules and regulations recently adopted by the Securities and Exchange Commission (the "SEC"), instead of mailing a printed copy of our proxy materials to each shareholder of record, we are now furnishing proxy materials to our shareholders on the Internet. If you received a Notice of Internet Availability of Proxy Materials by mail, you will not receive a printed copy of the proxy materials other than as described therein. Instead, the Notice of Internet Availability of Proxy Materials will instruct you as to how you may access and review all of the important information contained in the proxy materials. If you received a Notice of Internet Availability of Proxy Materials by mail and would like to receive a printed copy of our proxy materials, you should follow the instructions included in the Notice of Internet Availability of Proxy Materials.

It is anticipated that the Notice of Internet Availability of Proxy Materials is first being sent to shareholders on or about March 27, 2009. The proxy statement and the form of proxy relating to the 2009 Annual Meeting are first being made available to shareholders on or about March 27, 2009.

PROXIES SOLICITED BY:

The Board.

REVOKING YOUR PROXY:

You may revoke your proxy before it is voted at the Meeting. To revoke, follow the procedures listed on page 4 under "Voting Procedures/Revoking Your Proxy."

COMMENTS:

Your comments about any aspects of our business are welcome. You may use the space provided on the proxy card for this purpose, if desired. Although we may not respond on an individual basis, your comments help us to measure your satisfaction, and we may benefit from your suggestions.

PLEASE VOTE – YOUR VOTE IS IMPORTANT

Prompt return of your proxy will help reduce the costs of re-solicitation.

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* We expect to vote on this item at the Meeting.

VOTING PROCEDURES/REVOKING YOUR PROXY

You can vote by telephone, the Internet, mail or in person.

You may vote in person or by a validly designated proxy, or, if you or your proxy will not be attending the meeting, you may vote in one of three ways:

1. Vote by Internet. The website address for Internet voting is on your Notice of Internet Availability of Proxy Materials. Internet voting is available 24 hours a day;

2. Vote by telephone. The toll-free number for telephone voting is on your proxy card. Telephone voting is available 24 hours a day; or

3. Vote by mail. If you have requested and received a copy of our proxy materials, mark, date, sign and mail promptly a proxy card (a postage-paid envelope will be provided for mailing in the United States).

If you vote by telephone or Internet, DO NOT mail a proxy card.

Under Arizona law, a majority of the shares entitled to vote on any single matter which may be brought before the Meeting will constitute a quorum. Business may be conducted once a quorum is represented at the Meeting. If a quorum exists, action on a matter other than the election of directors will be deemed approved if a majority of votes is cast in favor of the matter.

Directors are elected by a plurality of votes.

Directors are elected by a plurality of the votes cast by the shares entitled to vote if a quorum is present. A plurality means receiving the largest number of votes, regardless of whether that is a majority. Withheld votes will be counted as being represented at the Meeting for quorum purposes but will not have an effect on the vote.

You may cumulate your votes for directors.

In the election of directors, each shareholder has the right to cumulate his votes by casting a total number of votes equal to the number of his shares of common stock multiplied by the number of directors to be elected. He may cast all of such votes for one nominee or distribute such votes among two or more nominees. For any other matter that may properly come before the Meeting, each share of common stock will be entitled to one vote.

You can revoke your proxy after sending it in by following these procedures.

Any shareholder giving a proxy has a right to revoke that proxy by giving notice to UniSource Energy in writing directed to the Corporate Secretary, UniSource Energy Corporation, One South Church Avenue, Suite 1820, Tucson, Arizona 85701, or in person at the Meeting at any time before the proxy is exercised. Those who fail to return a proxy or fail to attend the Meeting will not count towards determining any required plurality, majority or quorum.

The shares represented by an executed proxy will be voted for the election of directors or withheld in accordance with the specifications in the proxy. If no specification is made in an executed proxy, the proxy will be voted in favor of the nominees as set forth herein.

Proxy Solicitation

We will bear the entire cost of the solicitation of proxies. Solicitations will be made primarily by mail. In addition, we may make additional solicitation of brokers, banks, nominees and institutional investors pursuant to a special engagement of BNY Mellon Shareholder Services. Solicitations may also be made by telephone, facsimile or personal interview, if necessary, to obtain reasonable representation of shareholders at the Meeting. Our employees may solicit proxies but they will not receive additional compensation for such services. We will request brokers or other persons holding shares in their names, or in the names of their nominees, to forward proxy materials to the beneficial owners of such shares or request authority for the execution of the proxies. We will reimburse brokers and other persons for reasonable expenses they incur in sending these proxy materials to you if you are a beneficial holder of our shares.

UNISOURCE ENERGY SHARE OWNERSHIP

Security Ownership of Management

The following table sets forth the number and percentage of shares of UniSource Energy common stock beneficially owned as of March 1, 2009 and the nature of such ownership by each of our directors (all of whom are nominees), our Chief Executive Officer for 2008 ("CEO" or "Mr. Pignatelli") and our four other most highly compensated executive officers (together with our CEO, the "Named Executives") as of March 1, 2009 and all directors and officers as a group. Ownership includes direct and indirect (beneficial) ownership, as defined by the SEC rules.

Name and Title of Beneficial Owner	Amount and Nature of Beneficial Ownership(1)					Other(2)		
	Directly Owned Shares	Shares Purchased Under the 401(k) Plan	Shares Subject to Options Exercisable Within 60 Days	Total Beneficial Ownership	Percent of Class	Restricted Stock Units	Deferred Shares Under Deferred Compensation Plan	Total
James S. Pignatelli Chairman, President and Chief Executive Officer(3)	114,324	21,030	695,089	830,443	2.3%	0	30,971	**861,414**
Lawrence J. Aldrich Director	3,912	0	0	3,912	*	5,420	0	**9,332**
Barbara M. Baumann Director	0	0	0	0	*	3,869	8,965	**12,834**
Larry W. Bickle Director	9,852	0	8,358	18,210	*	4,492	0	**22,702**
Elizabeth T. Bilby Director	705	0	8,358	9,063	*	5,876	4,194	**19,133**
Harold W. Burlingame Director	4,625	0	8,358	12,983	*	6,636	0	**19,619**
John L. Carter Director	23,817	0	0	23,817	*	5,171	11,315	**40,303**
Robert A. Elliott Director	1,813	0	1,196	3,009	*	4,324	0	**7,333**
Daniel W. L. Fessler Director	2,511	0	2,358	4,869	*	8,942	0	**13,811**
Louise L. Francesconi Director(4)	0	0	0	0	*	0	0	**0**
Kenneth Handy(5) Director	25,662	0	0	25,662	*	0	0	**25,662**
Warren Y. Jobe Director	1,313	0	6,358	7,671	*	6,266	0	**13,937**
Ramiro G. Peru Director	1,000	0	0	1,000	*	1,565	0	**2,565**
Gregory A. Pivirotto Director	400	0	0	400	*	1,565	0	**1,965**
Joaquin Ruiz Director	300	0	0	300	*	3,869	0	**4,169**
Kevin P. Larson Senior Vice President Chief Financial Officer and Treasurer	43,199	2,605	96,235	142,039	*	0	1,323	**143,362**

Name and Title of Beneficial Owner	Amount and Nature of Beneficial Ownership(1)					Other(2)		
	Directly Owned Shares	Shares Purchased Under the 401(k) Plan	Shares Subject to Options Exercisable Within 60 Days	Total Beneficial Ownership	Percent of Class	Restricted Stock Units	Deferred Shares Under Deferred Compensation Plan	Total
Raymond S. Heyman Senior Vice President and General Counsel	6,296	3,455	86,542	96,293	*	0	87	**96,380**
Michael J. DeConcini Senior Vice President and Chief Operating Officer, Transmission and Distribution	13,932	5,480	163,769	183,181	*	27,214	971	**211,366**
Karen G. Kissinger Vice President, Controller and Chief Compliance Officer	42,789	0	37,037	79,826	*	0	1,985	**81,811**
All directors and executive officers as a group	358,339	58,635	1,290,400	1,707,374	4.8%	85,209	62,655	**1,855,238**

*Represents less than 1% of the outstanding common stock of UniSource Energy.

(1) Amounts include the following:

- Any shares held in the name of the spouse, minor children or other relatives sharing the home of the director or officer. Except as otherwise indicated below, the directors and officers have sole voting and investment power over the shares shown. Voting power includes the power to direct the voting of the shares held, and investment power includes the power to direct the disposition of the shares held.
- Shares subject to options exercisable within 60 days, based on information from E*Trade, UniSource Energy's stock option plan administrator.
- Equivalent share amounts allocated to the individuals' 401(k) Plan which, since June 1, 1998, has included a UniSource Energy Stock Fund investment option.

(2) While amounts in the "Other" column do not represent a right of the holder to receive stock within 60 days, these amounts are being disclosed because management believes they reflect similar objectives of 1) encouraging directors and officers to have a stake in the Company, and 2) aligning interests of directors and officers with those of shareholders. Under our non-employee director compensation program, non-employee directors receive an annual grant of restricted stock units that have an underlying value equal to one share of UniSource Energy common stock. The value of the restricted stock units fluctuates based on changes in the Company's stock price. All restricted stock unit grants to directors vest at the earlier of the next annual meeting following the grant date or the first anniversary of grant and are distributed in actual shares of Company stock in January following termination of Board service. Similarly, the value of deferred stock units fluctuates based on changes in the Company's stock price. Under the terms of the plan, distributions of deferred shares will be made in cash, unless the participant elects to receive the deferred shares in Company stock on dates selected by the director or the officer following termination of service. In our view, restricted stock units and deferred stock units are tantamount to actual stock ownership as the non-employee director and officer (in the case of deferred stock units) bear the risk of ownership during the restricted and deferral periods.

(3) Mr. Pignatelli retired effective as of January 1, 2009. His successor, Paul Bonavia, became Chairman of the Board, President and Chief Executive Officer, effective January 1, 2009. Since Mr. Bonavia does not beneficially own any UniSource Energy common stock which has vested, Mr. Bonavia was not included in this table.

(4) Ms. Francesconi was appointed to the Board, effective August 14, 2008.

(5) Mr. Handy retired from his position as a director effective as of January 1, 2009 and, therefore, is not being nominated as a director.

Security Ownership of Certain Beneficial Owners

As of March 1, 2009, based on information reported in filings made by the following persons with the SEC or information otherwise known to us, the following persons were known or reasonably believed to be, as more fully described below, the beneficial owners of more than 5% of our common stock:

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common	Barclays Global Investors, NA 45 Fremont Street San Francisco, CA 94105	3,321,505(1)	9.4%
Common	Luminus Management, LLC 1700 Broadway, 38th Floor New York, NY 10019	3,296,379(2)	9.3%
Common	Prospector Partners, L.L.C. 370 Church Street Guilford, CT 06437	2,670,686(3)	7.3%
Common	T. Rowe Price Associates, Inc. 100 E. Pratt Street Baltimore, MD 21202	2,506,350(4)	7.0%
Common	Wellington Management Co., LLP 75 State Street Boston, MA 02109	2,353,955(5)	6.8%
Common	Duquesne Capital Management, LLC 40 W. 57th Street, 25th Floor New York, NY 10019	1,781,000(6)	5.0%

(1) In a statement (Schedule 13G) filed with the SEC on February 6, 2009, Barclays Global Investors, NA, indicated that it has sole voting power over 2,801,812 shares of our common stock and sole dispositive power over 3,321,505 shares of our common stock. The filing indicated that the 3,321,505 shares are owned by Barclays Global Investors, NA (744,963 shares), Barclays Global Fund Advisors (2,539,447 shares), Barclays Global Investors, LTD (23,507 shares), Barclays Global Investors Australia Limited (13,588).

(2) In a statement (Schedule 13G) filed with the SEC on February 17, 2009, Luminus Management LLC, indicated it has sole voting and sole dispositive power over 3,296,379 shares of our common stock.

(3) In a statement (Schedule 13G) filed with the SEC on February 17, 2009, Prospector Partners, L.L.C. ("Prospector Partners"), indicated it has sole voting and sole dispositive power over 1,875,672 shares, and shared voting and shared dispositive power over 795,014 shares of our common stock. Prospector Partners shares investment discretion over 795,014 shares with White Mountains Advisors LLC ("White Mountains"), pursuant to a sub-advisory agreement between Prospector Partners and White Mountains.

(4) In a statement (Schedule 13G) filed with the SEC on February 13, 2009, T. Rowe Price Associates, Inc. ("Price Associates"), indicated it has sole voting power over 288,933 shares and sole dispositive power over 2,506,350 shares of our common stock. These securities are owned by various individual and institutional investors which Price Associates serves as investment adviser with power to direct investments and/or sole power to vote the securities. For purposes of the reporting requirements of the Securities Exchange Act of 1934, as amended, Price

Associates is deemed to be a beneficial owner of such securities; however, Price Associates expressly disclaims that it is, in fact, the beneficial owner of such securities.

(5) In a statement (Schedule 13G) filed with the SEC on February 17, 2009, Wellington Management Co. LLP, indicated it has shared voting power over 1,826,595 shares and shared dispositive power over 2,353,955 shares of our common stock.

(6) In a statement (Schedule 13G) filed with the SEC on February 12, 2009, Duquesne Capital Management, LLC, indicated it has shared voting power over 1,781,000 shares of our common stock and shared dispositive power over 1,781,000 shares of our common stock.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, and regulations of the SEC require our executive officers, directors and persons who beneficially own more than 10% of our common stock, as well as certain affiliates of those persons, to file initial reports of ownership and transaction reports covering any changes in ownership with the SEC and the New York Stock Exchange ("NYSE"). SEC regulations require these persons to furnish us with copies of all reports they file pursuant to Section 16(a).

Based solely upon a review of the copies of the reports received by us and on written representations of our directors and officers, we believe that during fiscal year 2008, all filing requirements applicable to executive officers and directors were complied with in a timely manner.

PROPOSAL ONE: ELECTION OF DIRECTORS

General Information

At the Meeting, our shareholders of record will elect 14 directors to serve on our Board for the ensuing year and until their successors are elected and qualified, which include our new Chief Executive Officer, Paul J. Bonavia, who joined UniSource Energy on January 1, 2009. The shares represented by executed proxies in the form provided, unless withheld, will be voted for the 14 nominees listed below, or, in the discretion of the persons acting as proxies, will be voted cumulatively for one or more of such nominees. All of the current nominees are present members of the Board. All of the nominees have consented to serve if elected. If any nominee becomes unavailable to serve for any reason, or a vacancy should occur before the election, it is the intention of the persons designated as proxies to vote, in their discretion, for other nominees.

BOARD NOMINEES

Paul J. Bonavia

Chairman of the Board, President and Chief Executive Officer of UniSource Energy since January 1, 2009; Chairman of the Board, President and Chief Executive Officer of Tucson Electric Power Company ("TEP") , the principal subsidiary of UniSource Energy, since January 1, 2009; Chairman of the Board, President and Chief Executive Officer of UniSource Energy Services, Inc. ("UES"), a wholly-owned subsidiary of UniSource Energy, since January 1, 2009; former President of the Utilities Group of Xcel Energy, an electric and gas utility, from December 2005-December 2008; and former President of Commercial Enterprises of Xcel Energy from 2004 to December 2005. Board member since January 1, 2009. Age 57.

Lawrence J. Aldrich (2)(4)

President and Chief Executive Officer of University Physicians Healthcare, a healthcare organization, since January 2009; President of Aldrich Capital Company, an acquisition, management and consulting firm, since January 2007; Chief Operating Officer of The Critical Path Institute, a non-profit medical research company focusing in drug development, from January 2006 to December 2006; General Partner of Valley Ventures, LP, a venture capital company, from September 2002 to December 2005; Managing Director and Founder of Tucson Ventures, LLC, a venture capital company, from February 2000 to September 2002; Director of TEP and Millennium since 2000; and Director of UES since 2004. Board member since 2000. Age 56.

Barbara M. Baumann (1)(3)

President and Owner of Cross Creek Energy Corporation, a management consultant and investor company for oil and gas, since 2003; Director of St. Mary Land & Exploration since 2002; and Director of TEP since 2005. Board member since 2005. Age 53.

Larry W. Bickle (2)(3)

Retired private equity investor; Managing Director of Haddington Ventures, LLC, a private equity fund, from 1997 to 2007; Director of St. Mary Land & Exploration, an oil and gas production company, since 1995; Director of Millennium from 1998-2008; and Director of UES since 2004. Board member since 1998. Age 63.

Elizabeth T. Bilby (4)(5)

Retired President of Gourmet Products, Inc., an agricultural product marketing company; retired Director of Marketing of Green Valley Pecans, a pecan producer; Director of TEP since 1995; Director of Millennium from 1998-2008; and Director of UES since 2004. Board member since 1995. Age 69.

Harold W. Burlingame (2)(5)(6)

Former Executive Vice President of AT&T, a telecommunications company; Chairman of ORC Worldwide since December 2004; and Director of TEP since 1998. Board member since 1998. Age 68.

John L. Carter (1)(2)(3)(4)(5)(6)

Retired Executive Vice President and Chief Financial Officer of Burr Brown Corporation, a company that manufactured integrated circuits, in 1996; Director of Global Solar Energy since January 2007, Director of TEP since 1996; Director of Millennium from 1998-2008; Director of UES since 2004; and UniSource Energy Lead Director since 2005. Board member since 1996. Age 74.

Robert A. Elliott (3)(4)(6)

President and owner of The Elliott Accounting Group, an accounting firm, since 1983; Director and Corporate Secretary of Southern Arizona Community Bank since 1998; Television Analyst/Pre-game Show Co-host for Fox Sports Arizona, television broadcasting, since 1999; Chairman of the Board of Tucson Metropolitan Chamber of Commerce from 2002 to 2003; Treasurer of Tucson Urban League from 2002 to 2003; Chairman of the Board of Tucson Urban League from 2003 to 2004; Chairman of the Board of the Tucson Airport Authority from January 2006 to January 2007; and Director of TEP since May 2003. Board member since 2003. Age 53.

Daniel W. L. Fessler (1)(3)(6)

Professor Emeritus of the University of California; Of Counsel for the law firm of Holland & Knight from August 2003-January 2007; Partner in the law firm of LeBoeuf, Lamb, Greene & MacRae LLP from 1997 to 2003; previously served on the UniSource Energy and TEP boards of directors from 1998 to 2003; Managing Principal of Clear Energy Solutions, LLC since December 2004; and Director of TEP since 2005. Board member since 2005. Age 67.

Louise L. Francesconi (2)(4)

Retired President of Raytheon Missile Systems, a defense electronics corporation; Director of Stryker Corporation from July 2006, Director of Global Solar Energy from June 2008, Director of TEP since August 2008; and Director of UES since August 2008; Board member since August 2008. Age 56.

Warren Y. Jobe (1)(4)(6)

Certified Public Accountant (licensed, but not practicing); Senior Vice President of Southern Company, an electric service company, from 1998 to 2001; Director of WellPoint Health Networks, Inc. from 2001 to December 2004; Director of WellPoint, Inc. since December 2004; Trustee of RidgeWorth Funds since 2004; Director of TEP since 2001; and Director of Millennium from 2001 to 2003. Board member since 2001. Age 68.

Ramiro G. Peru (2)(4)

Executive Vice President and Chief Financial Officer of Swift Transportation, a trucking company, from June 2007 to December 2007, Executive Vice President and Chief Financial Officer of Phelps Dodge Corporation, a mining corporation, from 2004 to 2007; Director of WellPoint Health Networks, Inc. since 2003; Director of Southern Peru Copper Corporation from 2002 to 2004; and Director of University of Arizona Foundation since 2005. Board member since January 2008. Age 53.

Gregory A. Pivirotto (1)(3)

President and Chief Executive Officer and Director of University Medical Center Corporation, a hospital, since 1994; Certified Public Accountant since 1978; Director of Arizona Hospital & Healthcare Association from 1997 to 2005; and Director of Tucson Airport Authority since 2008; Board member since January 2008. Age 56.

Joaquin Ruiz (3)(5)

Professor of Geosciences, University of Arizona since 1983; Dean, College of Science, University of Arizona since 2000; Vice President of the Geological Society of America beginning in 2009; Associate Editor, "American Journal of Science" since 2005; Associate Editor, American Presidents Advisory Board of Research Corporation since 2005; Member, Human Resources Committee, American Geological Institute from 2000 to 2005 and 2009-2012; Member, Governing Board, Instituto Nacional de Astronomia, Optica y Electronica, Mexico since 2003; Board Member, Center to Improve Diversity in Earth Systems Sciences, Inc. since 2003; Member of Board of Earth Sciences, National Research Council of the National Academy of Sciences since 2005; TEP Board Member since 2005; and UES Board member since 2005. Board Member since 2005. Age 57.

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(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Corporate Governance and Nominating Committee.
(4) Member of the Finance Committee.
(5) Member of the Environmental, Safety and Security Committee.
(6) Member of the Corporate Development Committee.

The Board recommends that you vote "FOR" these nominees.

PROPOSAL TWO: RATIFICATION OF SELECTION OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Audit Committee has selected PricewaterhouseCoopers, LLP ("Pricewaterhouse") as the Company's Independent Registered Public Accounting Firm for the fiscal year 2009, and the Board is asking the shareholders to ratify that selection. Although current law, rules, and regulations, as well as the charter of the Audit Committee, require the Audit Committee to engage, retain, and supervise the Company's Independent Registered Public Accounting Firm, the Board considers the selection of the Independent Registered Public Accounting Firm to be an important matter of shareholder concern and is submitting the selection of Pricewaterhouse for ratification by shareholders as a matter of good corporate practice.

Under Arizona law, if a quorum of shareholders is present at the Meeting, the ratification of the selection of PricewaterhouseCoopers as Independent Registered Public Accounting Firm for 2009 will require that the votes cast in favor of its ratification exceed the votes cast against its ratification. Abstentions and broker non-votes are counted for purposes of determining whether a quorum exists at the Meeting but are not counted and have no effect on the results of the vote for Independent Registered Public Accounting Firm.

The Board recommends that you vote "FOR" the ratification of the selection of the Independent Registered Public Accounting Firm.

COMPENSATION DISCUSSION AND ANALYSIS

The following Compensation Discussion and Analysis contains statements regarding future individual and Company performance targets and goals. These targets and goals are disclosed in the limited context of UniSource Energy's compensation programs and should not be understood to be statements of management's estimates of results or other guidance. UniSource Energy specifically cautions investors not to apply these statements to other contexts.

EXECUTIVE SUMMARY

At UniSource Energy, our mission is to deliver safe, reliable service and value to customers and shareholders alike. Our strategy includes enhancing shareholder value, maintaining customer satisfaction, expanding our role in the community, meeting environmental challenges and providing for our employees' development and well-being. We believe that our executive compensation program must align the interests of all our executive officers with this strategy to achieve our objectives.

UniSource Energy provides a balanced total compensation program that includes four components: base salary, short-term performance-based incentive, long-term performance-based incentive and other employee benefits.

In 2008, our continuing operations consisted mainly of the business conducted in three primary segments — TEP, UNS Gas, Inc., and UNS Electric, Inc. TEP, an electric utility, has provided electric service to the community of Tucson, Arizona, for more than 100 years. UNS Gas and UNS Electric provide natural gas and electric service in northern and southern Arizona. UNS Gas and UNS Electric are operating subsdiaries of UES, which was established in 2003 to oversee gas and electric properties acquired that year from Citizens Communications.

A significant part of our executive officers' compensation is based on our success in achieving annual corporate goals. These goals are designed to align the interest of our executive officers and all non-bargaining unit employees with our Company's strategy. The objectives of this incentive program and elements of compensation are discussed in detail below.

In 2008, our pursuit of these goals achieved mixed results. UniSource Energy demonstrated excellent performance relative to its cost containment, core business and customer service goals. The year was marked by a number of key accomplishments, including strong service reliability and customer service metrics and the approval of new rates for TEP and UNS Electric. However, two of the Company's three financial goals were not met. UniSource Energy's 2008 results were negatively impacted by higher fuel and purchased power expenses and other cost increases related to power plant maintenance and outages. Customer growth also slowed considerably at both TEP and UES compared to prior years and is expected to remain depressed through 2009 due to economic conditions.

In 2009, TEP will be operating under new rates approved in November 2008 by the Arizona Corporation Commission ("ACC"). The rates, which took effect in December 2008, represent a six-percent increase over the previous base rates and include a new Purchased Power and Fuel Adjustment Clause that will allow the utility to pass along changes in energy costs to customers.

The TEP rate order was the culmination of a multi-year effort led by James S. Pignatelli, who retired as Chairman, President and CEO of UniSource Energy at year's end. He was succeeded by Paul J. Bonavia, whose appointment as Chairman, President and CEO was effective January 1, 2009.

The objectives of UniSource Energy's executive compensation program and the elements of compensation are discussed in detail in the sections to follow.

COMPENSATION PHILOSOPHY

Objectives of the Compensation Program

We base our executive compensation policies and decisions with respect to our Named Executives on the achievement of the following objectives:

1. Attracting, motivating and retaining highly-skilled executives;
2. Linking the payment of compensation to the achievement of critical short- and long-term financial and strategic objectives, creation of shareholder value and provision of safe, reliable and economically available electric and gas service; and aligning performance objectives of management with those of other Company employees by using similar performance measures;
3. Aligning the interests of management with those of our stakeholders and encouraging management to think and act like owners, taking into account the interests of the public that the Company serves;
4. Maximizing the financial efficiency of the compensation program to avoid unnecessary tax, accounting and cash flow costs; and
5. Encouraging management to achieve outstanding results through appropriate means by delivering compensation in a manner consistent with established and emerging corporate governance best practices.

In support of the above objectives, UniSource Energy provides a balanced total compensation program that consists of four components:

- base salary;
- short-term performance-based incentive compensation;
- long-term performance-based incentive compensation; and
- benefits and perquisites.

Decisions made regarding each component of pay are considered in the context of each officer's total compensation. For example, if a decision is made to increase an executive's base salary, the resultant impact on short- and long-term performance-based incentive compensation and total compensation levels are evaluated relative to competitive practice (see "Benchmarking" discussion below). We do not consider the value of outstanding equity awards in setting annual total compensation opportunities as we believe that outstanding equity awards represent compensation for past service.

Each of these components is described in more detail below and in the narrative and footnotes to the supporting tables. The following illustrates how the above objectives are reflected in our compensation program:

Attracting, Retaining and Motivating Executive Talent

In support of our objective to attract, retain and motivate highly-skilled employees, we provide our Named Executives with compensation packages that are competitive with those offered by other electric and gas service companies of comparable size and complexity and/or electric and gas service companies thought to be competitors for executive talent.

The Compensation Committee generally targets base salary and short-term incentive opportunities, as well as the allocation among those elements of compensation for the Named Executives, at the median market rates of selected comparable companies identified below under the "Benchmarking" section. Long-term incentive opportunities are targeted at the 75th percentile of such market rates. Target compensation for individual executives range above or below those benchmarks based on a variety of factors, including each executive's skill set and experience relative to the general market, the importance of the position to the Company and the difficulty of replacing the executive, and the executive's past and expected future contribution to our success. Overall, total direct compensation for 2008 (i.e., salary, 2008 target PEP awards, and present value of 2008 long-term incentive awards) for the Named Executives fell between the median and 75th percentile of market rates.

In addition to providing competitive direct compensation opportunities, the Company also provides certain indirect compensation and benefits programs that are intended to assist in attracting and retaining high quality executives. These programs include pension and retirement programs and are described in more detail below and in the narratives that accompany the tables that follow this Compensation Discussion and Analysis section.

Linking Compensation to Performance

Our compensation program seeks to link the actual compensation earned by our Named Executives to their performance and that of the Company. We achieve this goal primarily through two elements of our compensation package: (i) short-term cash awards and (ii) equity-based compensation. To ensure that the senior executives are held most accountable for achieving our financial, operational and strategic objectives and for creating shareholder value, we believe that the percentage of pay at risk should increase with the level of responsibility within the Company. The target amounts of performance-based pay programs (i.e., cash incentive and equity-based compensation) comprise approximately 55% to 65% of the total direct compensation opportunity for our Named Executives. Of the performance-based compensation, approximately 30-45% is short-term and 55-70% is long-term. Placing a greater emphasis on long-term performance-based compensation encourages executives to focus on the long-term impact of their actions. Non-variable compensation, such as salary and perquisites, is de-emphasized in the total compensation program to reinforce the linkage between compensation and performance.

Aligning the Interests of our Named Executive Officers with Stakeholders

Our compensation program also seeks to align the interests of our Named Executives with those of our key stakeholders, including customers, employees and shareholders. We use the short-term incentive compensation component to focus the Named Executives on the importance of providing safe and reliable customer service, creating a safe work environment for our employees and improving financial performance by linking a significant portion of their short-term cash incentive compensation to achievement of these objectives. We primarily rely on the equity compensation element of our compensation package to align the interests of the Named Executives with those of shareholders through a mix of stock options and stock awards that vest based on the achievement of performance goals set by the Compensation Committee. We also encourage senior executives to accumulate a substantial stake in the Company.

Maximizing the Financial Efficiency of the Program

In structuring the total compensation package for our Named Executives, the Compensation Committee evaluates the accounting cost, cash flow implications and tax deductibility of compensation to mitigate financial inefficiencies to the greatest extent possible. For instance, as part of this process, the Compensation Committee evaluates whether compensation costs are fixed or variable and places a heavier weighting on variable pay elements to calibrate expense with the achievement of operating performance objectives and delivery of value to shareholders. In addition, the Compensation Committee takes into account the objective of having the incentive-based compensation components qualify for tax deductibility under Section 162(m) of the Internal Revenue Code, as amended (the "Code"). See discussion under "Impact of Regulatory Requirements" on page 23. The Compensation Committee also considers the cash flow and share dilution implications of cash versus equity-based incentive plans.

Adhering to Corporate Governance Best Practices

The Compensation Committee seeks to continually update the executive officer compensation program to reflect corporate governance best practices. For example, the Compensation Committee has established formal stock ownership guidelines that encourage each Named Executive to accumulate a meaningful amount of Company stock. Additionally, equity-based awards contain a "double-trigger" vesting provision, which provides for accelerated vesting in the event of a future change in control only if the executive is adversely impacted by the transaction. See discussion under "Potential Payments Upon Termination or Change in Control".

Benchmarking

The Compensation Committee considers the following factors for purposes of establishing salaries and variable compensation opportunities: (i) the competitive environment for Named Executives and what relevant competitors pay, and (ii) the need to provide each element of compensation and the amounts targeted and delivered.

To provide a foundation for the executive compensation program, UniSource Energy periodically benchmarks its named executive officers' compensation levels and practices against a peer group of companies intended to represent our competitors for business and talent. The peer group, which is reviewed periodically, includes the 17 electric and gas utility companies named below that are comparable to UniSource Energy in terms of size as measured by annual revenues and market capitalization. Except as described below, this group is the same peer group for 2008 that was used in prior competitive analyses, with the exception of Otter Trail Power Company and Southern Union Co., which were omitted from the peer group for 2008 due to differences in business models, and with the exception of North Western Corp., Piedmont Natural Gas Co., Pinnacle West Capital Corp., and Portland General Electric Co., which were included for 2008 due to similarity of business models, similar size, or because they were thought to be a competitor for executive talent. A review of UniSource Energy's executive compensation levels relative to the peer group was conducted in October 2008, and a review of aggregate long-term incentive cost and share usage practices relative to the peer group was last conducted in October 2007. UniSource Energy's 2007 revenues were between the 25th percentile and the median of the peer companies; market capitalization as of September 2008 was between the 25th percentile and the median of the peer companies.

2008 Peer Group:

AGL Resources Inc.	DPL Inc.	North Western Corp.	Portland General Electric Co.
Avista Corp.	El Paso Electric Co.	Piedmont Natural Gas Co.	South Jersey Industries Inc.
CH Energy Group Inc.	IDACORP Inc.	Pinnacle West Capital Corp.	Southwest Gas Corp.
Cleco Corporation	Northwest Natural Gas Co.	PNM Resources Inc.	UIL Holdings Corp.
			Westar Energy Inc.

The benchmark information is supplemented annually with information from Frederic W. Cook and Co., Inc., the independent consultant retained by the Compensation Committee, relating to general market trends, changes in regulatory requirements related to executive compensation and emerging best practices in corporate governance. See discussion relating to compensation consultant under "Compensation Consultant" on page 43.

ELEMENTS OF COMPENSATION

Base Salary

Base salary is used to provide each Named Executive a set amount of money during the year with the expectation that he or she will perform his or her responsibilities to the best of his or her ability and in the best interests of our Company. We believe that competitive base salaries are necessary to attract and retain executive talent critical to achieving the Company's business goals. In general, our Named Executives' base salaries are targeted to the median of the peer group described above. However, individual salaries can and do vary from the benchmark median data based on such factors as individual performance, potential for future advancement, the importance of the executive's position to the Company and the difficulty of replacement, current responsibilities, length of time in the current position, and, for recently hired executives, their prior compensation packages. Currently, all of our Named Executives' salaries, other than the CEO's, are within 10 percent of the benchmark median. For 2008, the CEO's salary approximated the 75th percentile in recognition of his leadership through the years, contributions to the growth of the Company, long tenure and strong performance.

Increases to Named Executives' base salaries are considered annually by the Compensation Committee. In approving base pay increases for Named Executives other than the CEO, the Compensation Committee also considers recommendations made by the CEO.

In December 2008, the Compensation Committee approved base salary increases for the Named Executives (other than Mr. Pignatelli, who retired effective as of January 1, 2009), for 2009. The following table indicates the Named Executives' base salaries for 2008 and 2009:

Name	*2008 Base Pay*	*Approved 2009 Base Pay*
James S. Pignatelli	$726,000	Not applicable
Kevin P. Larson	$316,000	$327,000
Michael J. DeConcini	$321,000	$332,200
Raymond S. Heyman	$316,000	$327,000
Karen G. Kissinger	$249,000	$257,400

The salary increases for the Named Executives were consistent with salary increases as a percent of salary for other non-represented employees.

Short-Term Incentive Compensation (Cash Awards)

The Compensation Committee provides for short-term incentive compensation in the form of cash awards under the Performance Enhancement Plan ("PEP") in order to link a significant portion of the Named Executives' annual compensation to the Company's annual financial and operational performance.

Each year, before the end of the first quarter, the Compensation Committee establishes performance objectives that must be met in whole or in part before the Company pays PEP awards. The Compensation Committee generally attempts to align the target opportunity for each Named Executive with the median rate for equivalent positions at the benchmark companies. In 2008, the target incentive opportunity for the Named Executives ranged from 40% to 80% of base salary, depending on position. As described more fully below, the actual amounts paid depend on the achievement of specified performance objectives, and could range from 50% of the target award upon achievement of threshold performance to 150% of the target award upon achievement of outstanding performance. The Compensation Committee has the discretion to increase, reduce or eliminate a PEP award regardless of whether the performance goals applicable to the Named Executive's incentive award have been achieved.

Financial and Operating Performance Objectives-2008

The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in the Company's performance plan for non-represented employees. In 2008, the financial and operating objectives were diluted earnings per share ("EPS"), operating cash flow, cost containment ("O&M") and customer service and core business goals relating to customer service, regulatory, reliability, project implementation and safety matters.

The measures and individual weightings for the 2008 PEP were selected by the Compensation Committee to ensure an appropriate focus on profitable growth, cash flow generation and expense control, as well as operational and customer service excellence. We think that this approach encourages all employees to work toward common goals that are in the interests of our various stakeholders including customers, employees and shareholders.

The Compensation Committee selected diluted EPS as a performance measure to work in tandem with the Company's reporting metrics to the financial community. In 2008, 20% of the PEP award was based on attaining the diluted EPS targets, 20% of the PEP award was based on attaining operating cash flow targets, 20% was based on keeping O&M costs within a specified range, and the remaining 40% was based on the achievement of our customer service and core business goals. The cash flow target, which was not a performance measure in 2007, was selected in 2008 as a performance measure to focus employees on generating cash for the Company during 2008 and in future years.

In developing the PEP performance targets, the Chief Financial Officer ("CFO") of the Company, with assistance from other personnel, compiles relevant data and makes recommendations to the Compensation Committee for a particular year, but the Compensation Committee ultimately determines the performance objectives that are adopted.

The 2008 quantitative performance objectives included:

2008 Performance Objectives	Threshold	Target	Outstanding
Diluted EPS	$ 1.70 per share	$ 1.95 per share	$ 2.20 per share
Operating Cash Flow	$ 280 million	$ 298 million	$ 315 million
O&M	$ 294 million	$ 289 million	$ 284 million

In addition, the 2008 customer service and core business goals included:

- Averaging customer service response time at or below 3 minutes;
- Volunteering community service of at least 38,000 hours by employees;
- Completing specific departmental project goals;
- Achieving various operational reliability goals; and
- Maintaining OSHA incident rates at or below industry average and implementing a safety awareness program.

Short-Term Incentive Award to the CEO

Because the CEO's total compensation could exceed $1 million, section 162(m) of the Internal Revenue Code ("Section 162(m)") would deny the Company a tax deduction for the excess over $1 million, unless that excess compensation qualified as performance-based compensation. To comply with the performance-based compensation requirements, and also allow the Compensation Committee to retain some discretion to reduce the PEP award, if appropriate, the Compensation Committee used a different approach from that described above for the Named Executives and other employees, requiring two separate steps, to calculate the CEO's short-term incentive award.

The first step involved the 2006 Omnibus Stock and Incentive Plan (the "2006 Omnibus Plan"), which permits payment of cash awards up to $2 million. For the CEO's short-term incentive award to qualify as performance-based compensation, Section 162(m) requires that the award be payable solely upon the attainment of performance goals. If the performance goals are achieved, Section 162(m) would permit the Compensation Committee to pay the amount specified at the time of the award or to pay any lesser amount, but would not allow payment of any greater amount. For the CEO's short-term incentive award, the Compensation Committee established a minimum attainment of cash from operations of at least $256 million for 2008, which, if achieved, would allow the Committee to pay the CEO the $2 million maximum permitted by the 2006 Omnibus Plan or any lesser amount; however, if the Company failed to achieve $256 million of cash from operations, the CEO would not be entitled to any short-term incentive award payment, regardless of the achievement of other PEP performance objectives as described above. In this respect, the CEO's performance objective differed significantly from objectives set for the awards to the other Named Executives. The CEO's award had an absolute minimum performance level that must have been achieved before the CEO received any payment, whereas if the Company failed to achieve the minimum performance on the operating cash flow objective set under the PEP, the other Named Executives could have still received a payment based on the attainment of the remaining performance objectives. Solely for purposes of this first step of determining the CEO's short-term incentive award, the Committee felt it was appropriate to set the CEO's operating cash flow performance objective slightly below the operating cash flow threshold used for the other Named Executives, because of the increased importance of the CEO's operating cash flow target, the increased risk related to that target, and the desire to comply with the performance-based compensation requirement of Code Section 162(m).

The second step for determining the CEO's short-term incentive award involved applying the PEP performance objectives and methodology. Once the Company achieved the minimum performance objective established pursuant to the 2006 Omnibus Plan for the CEO to receive any payment, the amount of the CEO's payment, including whether the CEO received the minimum, target or maximum amount as a percentage of base salary, would be determined using the same PEP performance objectives and methodology as described above for the other Named Executives.

As described above, the range of actual payouts would in all cases be less than the maximum amount permitted by the 2006 Omnibus Plan and would satisfy the performance-based compensation requirements of Section 162(m). Using the PEP guidelines, the Compensation Committee determined that the CEO's threshold, target and maximum annual incentive awards should be $290,400 (50% of his target award), $580,800 (100% of his target award and 80% of his base salary), and $871,200 (150% of his target award), respectively.

PEP Results

In 2008, the Company achieved $0.39 per share of diluted EPS, which was below the threshold level of performance of $1.70 per share. The Company achieved operating cash flow for 2008 of $277 million, which was also below the threshold level of performance of $280 million. In 2008, the Company achieved an O&M spending level for 2008 of $286.1 million, as shown in Table A below, which, because lower O&M spending represented better performance, was better than the target level of performance.

Table A, below, reflects the O&M cost containment goal, which ranged from $294 million (threshold) to $284 million (outstanding), and the corresponding payout levels, which ranged from 50% to 150% of the target award, as well as the O&M spending level achieved for 2008. O&M spending must have been less than $294 million to produce a payout; O&M spending in excess of $294 million would not have paid any amount for that performance target. According to the guidelines set by the Compensation Committee at the time of the award, which required interpolating on a straight-line basis, the achievement of the better than the target level of performance of the O&M spending target resulted in a payout level of 129% of the target amount for that factor.

Table A

										286.1		
O&M	Range ($ Millions)	294	293	292	291	290	289	288	287	286	285	284
Payout	Payout %	50%	60%	70%	80%	90%	100%	110%	120%	130%	140%	150%
										129%		

Table B, below, reflects the performance on the customer service and core business goals, which ranged from earning 200 points (threshold) to 500 points (outstanding), and the corresponding payout levels, which ranged from 50% to 150% of the target award. A greater number of points earned from the achievement of each goal, resulted in a greater level of performance. As shown in the table below, during 2008 the Company achieved 490 points from the customer service and core business goals.

Table B

					490
Core Business & Customer Service Payout	Range (Points)	200	300	400	500
	Payout %	50%	83%	117%	150%
					146%

The Company had five major categories of customer service and core business goals: Customer Service (which is generally discussed above), Reliability (which pertains to the operational reliability of the generation, transmission and distribution systems), Project Implementation (which pertain to six specific key departmental goals), Safety (which are discussed above), and Regulatory (which pertain to rate cases and compliance with certain regulatory requirements by subsidiary companies, as discussed below). Each category of goals earned points; Regulatory was worth 250 points (50% of the total points possible), with the other categories worth 62.5 points each. Each category of goals contains several sub-goals that share the total points available in each category. Quantitative and qualitative goals are included, and points are accumulated based on achievement of each sub-goal.

In the Regulatory category, there were four sub-goals, which included: (i) obtaining a rate case settlement agreement with the ACC for TEP, one of our electric subsidiaries; (ii) filing and advancing a rate case with the ACC for our gas subsidiary; (iii) obtaining approval from the ACC for the Renewable Energy Standard Tariff implementation, which satisfies Arizona-specific regulations; and (iv) completion by UNS Electric, Inc., which is also one of our electric subsidiaries, of its rate case filed with the ACC.

All Regulatory goals were achieved in 2008, contributing 250 points to the core and customer service business goals. All Safety, Customer Service, Reliability, and five out of the six Project Implementation goals were achieved. In 2008, the Company earned a total of 490 points for the customer service and core business goals, which was close to an outstanding level of performance. According to the guidelines set by the Compensation Committee at the time of the award, which required interpolating on a straight-line basis, the achievement of the these goals resulted in a payout level of 146% of the target amount for that factor.

Overall, these results produced total weighted performance for 2008 of 84.3% of target performance.

The Compensation Committee agreed and approved a PEP payout of 84.3% of target awards for Named Executives other than Mr. Pignatelli.

Mr. Pignatelli was eligible for a payment on account of his annual incentive award because the Company exceeded the minimum threshold of $256 million operating cash flow necessary for him to receive a payment. Having confirmed that Mr. Pignatelli was eligible for a payment, the Compensation Committee used the methodology described above to determine that Mr. Pignatelli was entitled to receive a payment of $500,000, or 86.1% of his target award. This payment, as a percent of the target award, was slightly higher than the payments to other Named Executives and reflects Committee use of discretion to recognize Mr. Pignatelli's leadership with respect to strategic initiatives and executive transition issues.

Long-Term Incentive Compensation (Equity Awards)

We believe that equity awards, in tandem with our executive stock ownership guidelines discussed below, encourage ownership of Company stock by executive officers and hold executive officers accountable for the long-term impact of their actions, which in turn aligns the interest of those officers with the interest of our shareholders. In addition, the vesting provisions applicable to the awards encourage a focus on long-term operating performance, link compensation expense to the achievement of multi-year financial results and help to retain executive officers.

The long-term incentive opportunity for each Named Executive is based on a multiple of salary. The current long-term incentive multiple, which is 100% of base salary for each Named Executive, was established in 2003 to retain the executives in light of a then pending merger. The value of the Named Executives' long-term incentive multiples, which is generally consistent with the median to 75th percentile of benchmark practice, has been maintained for the Named Executives to strengthen the retention value of the compensation program following the termination of the proposed merger transaction in 2004 and to avoid a reduction in Named Executives' compensation, which would allow some of the Named Executives to terminate employment for "good reason" and receive change in control severance benefits. See "Elements of Post-Employment Compensation – Termination and Change in Control" for greater detail. While Mr. Heyman is not covered under a change in control agreement, the Compensation Committee set his long-term incentive opportunity at 100% of salary to advance internal pay equity with the other Named Executives with comparable responsibility levels. Mr. Pignatelli's long-term incentive opportunity of 100% of salary is below the targeted 75th percentile and his total direct compensation falls between the median and 75th percentile.

In developing the long-term performance targets, the CFO of the Company compiles relevant data and makes recommendations to the Compensation Committee, but the Compensation Committee ultimately determines the performance objectives that are adopted for the applicable long-term plan.

For 2008, management recommended and the Compensation Committee approved long-term incentive awards consisting of equally weighted stock options and performance shares with earnout tied to total shareholder return

("TSR"). Given the difficulty in projecting the outcome of the TEP rate case, which occurred in 2008, and the unpredictable impact of the TEP rate case on diluted EPS, the Compensation Committee decided to use TSR as the performance metric for 2008, rather than cumulative diluted EPS. TSR was selected as the performance objective as it rewards executives for creating value in excess of a broad index of utilities. We believe that this long-term incentive approach consisting of stock options and TSR-based performance shares focuses the Named Executives on increasing both absolute and relative shareholder value creation. Moreover, stock option grants and performance share awards are intended to qualify as performance-based compensation under Section 162(m) of the Code, which is tax deductible by the Company.

Stock Option Grants

Options are designed, in part, to reward longer term success in Company performance that is reflected in increases in share price. The Company's options, granted with an exercise price equal to the fair market value on the date of grant, help focus executives on long-term growth. In addition, options are intended to help retain key employees because they become exercisable in one-third increments over a three year period. The three-year incremental vesting also keeps executives focused on long-term performance.

Performance Share Awards

Performance shares are designed, in part, to reward achievement of financial performance objectives and/or shareholder value objectives.

2008 Program

The 2008 performance share awards are tied to TSR, relative to the Edison Electric Institute index, over a three-year performance period, commencing in 2008 and ending in 2010. The 2008 performance share criteria were established at the beginning of 2008 and are set forth in the following table.

PERFORMANCE CRITERIA

TSR Percentile Rank	Payout as a Percent of Target Award
75th percentile and above	150%
60th percentile – 74th percentile	125%
50th percentile – 59th percentile	100%
40th percentile – 49th percentile	75%
35th percentile – 39th percentile	50%
Below 35th percentile	0%

2006 Program

The 2006 performance share awards were tied to the achievement of Basic EPS (defined as EPS applied to undiluted outstanding shares), and operating cash flow goals over the 2006-2008 performance period.

The cumulative Basic EPS for the 2006-2008 performance period was $3.96 per share, which is less than threshold, and resulted in no payment on the Basic EPS goal. The cumulative operating cash flow was $882.3 million and resulted in a 33% operating cash flow payout. See the "Outstanding Equity Awards Table" on pages 29-31 for the number and market value of unearned share awards for each of the Named Executives.

Table C, below, reflects the cumulative Basic EPS goal, which ranged from $5.80 per share (threshold) to $6.38 per share (outstanding), and the corresponding payout levels, which ranged from 25% to 75% of the target award. As noted above, the cumulative Basic EPS for the three year period comprising 2006-2008 was less than the threshold level, as shown on the table below; therefore, there was no payout on the Basic EPS goal.

Table C

		Actual	Threshold	Target	Outstanding
EPS - Basic	Range	$3.96	$5.80	$6.07	$6.38
	Payout %	0%	25%	50%	75%

Table D, below, reflects the operating cash flows goals, which ranged from $879.6 million (threshold) to $901.1 million (outstanding), and the corresponding payout levels which ranged from 25% to 75% of the target award. As shown on the table below, the Company achieved a cumulative operating cash flows level of $882.3 million, which resulted in a payout level of 33% of the target amount for that factor.

Table D

		Threshold	Actual	Target	Outstanding
Cash Flow	Range ($ Millions)	$879.6	$882.3	$888.3	$901.1
	Payout %	25%	33%	50%	75%

The targets and goals discussed above are disclosed in the limited context of UniSource Energy's compensation programs and should not be understood to be statements of management's estimates of results or other guidance. UniSource Energy specifically cautions investors not to apply these statements to other contexts.

Equity Grant Timing and Practice

Generally, during the first quarter following the close of a fiscal year, the Compensation Committee approves the long-term incentive awards to be granted for the upcoming year, including the type of equity to be granted, as well as the size of the awards for Named Executives. In determining the type and aggregate size of awards to be provided, as well as the performance metrics that will apply, the Compensation Committee considers the strategic goals of the Company, trends in corporate governance, accounting impact, tax deductibility, cash flow considerations, the impact on EPS and the number of shares that would be required to be allocated for the award and the resulting impact to shareholders. When the Compensation Committee approves grants of plan-based equity awards, the exercise price is set at the market closing price of UniSource Energy common stock on the date that the grant is made. Awards are not coordinated with the release of material non-public information.

In addition, the Company does not typically provide for off-cycle stock option grants and has no specific number of shares under the 2006 Omnibus Plan set aside for such grants. However, occasionally in connection with a new hire of an executive, such a grant may be made to the extent approved by the Compensation Committee. The exercise price of any off-cycle option granted to a newly hired executive will be the closing market price on the date that the Compensation Committee approves any such award, consistent with the pricing practices associated with on-cycle plan-based equity awards.

STOCK OWNERSHIP POLICY

To further support our objective of aligning management and shareholder interests, the Company maintains a formal stock ownership policy, which encourages all officers to accumulate a substantial ownership stake in Company shares. The policy has the following key features:

- Participants are encouraged to accumulate Company shares with a target value of a multiple of their base salary, ranging from one times base salary for Vice Presidents, three times for senior Vice Presidents and five times for our CEO.

- If a participant has not yet reached the applicable target ownership requirement, he or she is expected to retain a portion of the net after-tax shares acquired from any stock option exercise, vesting of restricted stock or payments related to the performance share program. The applicable retention rates are 100% for the CEO, 50% for Named Executives who are senior Vice Presidents and 25% for the other Vice Presidents.

- Unexercised stock options, unvested stock options and unearned performance shares do not count towards meeting the ownership guidelines.

Annually, management provides a report to the Compensation Committee regarding the number and value of the shares held by each officer subject to the guidelines. As of December 31, 2008, all of the Named Executives who were hired before 2005, including the CEO, have achieved their target ownership level. Raymond S. Heyman, who was hired after 2005, is making progress toward meeting the guideline.

OTHER COMPENSATION

Perquisites

The Company provides Named Executives with limited personal benefits and perquisites. These are not tied to any formal individual or Company performance criteria but are intended to enhance the attraction and overall retention value of the executive compensation program and to be comparable to similar benefits provided to executives and other key personnel in other similar companies in the industry. As a benefit, the Company from time to time reimburses certain executives for business or similar social club initiation fees and periodic special assessments. The Company also reimburses executives for the travel expenses of their spouses incurred in connection with the annual Board strategic retreat. The Company also has a policy of either directly paying or reimbursing certain executives for certain of their relocation costs, since this is a common benefit offered in the market and an additional means of attracting executives. None of our Named Executives benefited from the relocation policy during 2008. For identification of specific perquisites and associated values, refer to the "Summary Compensation Table" on page 25.

Retirement Benefits

Our Named Executives are also eligible to participate in certain employee benefits plans and arrangements offered by the Company. These include the Tucson Electric Power Company 401(k) Plan, the Tucson Electric Power Company Salaried Employees Retirement Plan (the "Retirement Plan"), the Tucson Electric Power Company Excess Benefit Plan (the "Excess Benefit Plan") and the Management and Directors Deferred Compensation Plan (the "DCP"). A description of the pension and other retirement plans is provided under "Elements of Post-Employment Compensation-Retirement and Other Benefits," below.

ELEMENTS OF POST-EMPLOYMENT COMPENSATION

Termination and Change in Control

In 1998, TEP, a wholly owned subsidiary of the Company, entered into Change in Control Agreements ("Change in Control Agreements" or "Agreements") with all of the then Named Executives to help keep them focused on their work responsibilities during the uncertainty that accompanies a change in control, to provide benefits for a period of time following certain terminations of employment after a change in control event or transaction and to help us attract and retain key personnel. Some of these Agreements remain in effect until 2010. See discussion preceding the "Potential Payments Upon Termination or Change in Control Table" on page 34.

Retirement and Other Benefits

Benefits Generally

The Company offers retirement and other core benefits to its employees, including executive officers, in order to provide them with a reasonable level of financial support in the event of illness or injury and to enhance productivity and job satisfaction. The benefits are the same for all employees and executive officers and include medical and dental coverage, disability insurance and life insurance. In addition, the Tucson Electric Power Company 401(k) Plan and the Retirement Plan provide a reasonable level of retirement income reflecting employees' careers with the Company. All employees, including executive officers, participate in these plans; the cost of these benefits (other than the Retirement Plan) is partially borne by the employee, including each executive officer. To the extent that any officer's retirement benefit exceeds Internal Revenue Service ("IRS") limits for amounts that can be paid through a qualified plan, the Company also offers non-qualified retirement plans, including the Excess Benefit Plan and the DCP. These plans provide only the difference between the calculated benefits and the IRS limits. Benefits under the Excess Benefit Plan are provided to officers but, with limited exceptions, are not generally available to other employees. These benefits are not tied to any formal individual or Company performance criteria but are intended to enhance the attraction and retention value of the executive compensation program and are consistent with similar competitive compensation benefits made available to executives in the industry. We believe the DCP assists with our attraction and retention objectives since it provides an industry-competitive and tax-efficient benefit to our executives. The DCP is not funded by the Company and participants have an unsecured contractual commitment by the Company to pay amounts owed under the DCP. For more information on retirement and certain related benefits, see the discussion following the "Pension Benefits Table" on page 33 and the "Non-Qualified Deferred Compensation Table" on page 34.

IMPACT OF REGULATORY REQUIREMENTS

Under Section 162(m) of the Code, compensation paid to the CEO and to certain other most highly compensated executives in excess of $1,000,000 annually is not deductible for federal income tax purposes unless the compensation is awarded under a performance-based plan approved by the shareholders, and satisfies certain other requirements. To the extent that the Company complies with the performance-based compensation provision of Section 162(m), the awards granted to the CEO and other Named Executives are tax deductible by the Company. The Company believes that all executive compensation earned in 2008 will be tax deductible.

The Compensation Committee believes that it is in the best interest of the Company to receive maximum tax deductibility for compensation paid to the Company's Named Executives, although to maintain flexibility in compensating Named Executives in a manner designed to promote varying corporate goals, the Compensation Committee may award compensation that is not fully deductible under certain circumstances. The Company's compensation plans reflect the Compensation Committee's intent and general practice to pay compensation that the Company can deduct for purposes of federal income tax. Executive compensation decisions, however, are multifaceted. The Compensation Committee reserves the right to pay amounts that are not tax deductible to meet the design goals of our executive compensation program.

The Compensation Committee also considers other financial implications when developing and implementing the Company's compensation program, including accounting costs, cash flow impact and potential share dilution.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Compensation Committee has reviewed and discussed with management the "Compensation Discussion and Analysis" section required by Item 402(b) of SEC Regulation S-K and contained in this Proxy Statement. Based on such review and discussions, the Compensation Committee recommended to the Board that the "Compensation Discussion and Analysis" section be included in the Company's annual report on Form 10-K for the year ended December 31, 2008 and the 2009 Proxy Statement.

Respectfully submitted,

THE COMPENSATION COMMITTEE

Harold W. Burlingame, Chair
Lawrence J. Aldrich
Larry W. Bickle
John L. Carter
Louise L. Francesconi
Ramiro G. Peru

SUMMARY COMPENSATION TABLE—2008

The following table sets forth summary compensation information for the years ended December 31, 2006, December 31, 2007, and December 31, 2008 for our CEO, our CFO and three other most highly compensated Named Executives:

Name and Principal Position	Year ($)	Salary ($)	Stock Awards ($)(1)	Option Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	Change in Pension Value and Non-Qualified Deferred Compensation Earnings ($)(4)	All Other Compensation ($)(5)	Total ($)
James S. Pignatelli Chairman, President and Chief Executive Officer	2008	724,689	98,305	348,790	500,000	793,548	13,532	2,478,864
	2007	694,438	97,755	319,336	791,000	0	262,236	2,164,765
	2006	666,923	95,476	339,742	867,500	210,550	17,646	2,197,837
Kevin P. Larson Senior Vice President and Chief Financial Officer	2008	315,499	46,397	137,107	132,700	208,912	14,366	854,981
	2007	299,814	62,731	85,372	237,632	0	49,237	734,786
	2006	288,462	41,317	32,671	259,184	74,313	15,352	711,299
Michael J. DeConcini Senior Vice President and Chief Operating Officer, Transmission and Distribution	2008	320,112	46,910	137,776	134,800	161,064	15,485	816,147
	2007	300,178	62,731	85,372	243,608	0	74,960	766,849
	2006	288,462	41,317	32,671	265,196	38,573	14,768	680,987
Raymond S. Heyman Senior Vice President and General Counsel	2008	319,949	46,397	224,702	132,700	159,468	14,408	897,624
	2007	304,077	62,731	208,484	146,000	43,651	14,183	779,126
	2006	288,462	41,317	155,783	167,000	65,352	14,020	731,934
Karen G. Kissinger Vice President, Controller and Chief Compliance Officer	2008	248,493	36,536	124,994	83,700	205,525	11,182	710,430
	2007	236,731	49,647	67,598	179,648	0	13,011	546,635

(1) The amounts included in the "Stock Awards" column represent the compensation expense recognized by the Company for performance share awards during 2006, 2007 and 2008, calculated in accordance with Statement of Financial Accounting Standards share based payment (revised 2004) ("FAS 123R"). The Company's FAS 123R assumptions used in these calculations are set forth on pages 149-152 of our annual report on Form 10-K filed with the SEC on March 2, 2009, and available on the Company's website at www.UNS.com.

(2) The amounts included in the "Option Awards" column represent the compensation expense recognized by the Company for stock option awards granted to the Named Executives during 2006, 2007 and 2008, and a 2005 stock option award to Mr. Heyman, calculated in accordance with FAS 123R. The Company's FAS 123R assumptions used in these calculations are set forth on pages 149-152 of our annual report on Form 10-K filed with

the SEC on March 2, 2009, and available on the Company's website at www.UNS.com. Since Mr. Pignatelli was retirement eligible, his accruals in 2006, 2007 and 2008 were fully expensed during the year of the award, rather than expensed over a three-year vesting period. These amounts disregard estimates of forfeitures related to service based vesting conditions.

(3) The 2008 PEP awards included in this column were paid during the first four months of 2009.

(4) This column reflects the change in the actuarial present value of the accumulated benefit under all defined benefit plans (the Retirement Plan and Excess Benefit Plan). Due to a change in actuarial assumptions for the 2007 measurement date, the change in pension value for four of the Named Executives was negative for 2007, and in accordance with the SEC rules, we report these amounts as zero. We do not pay "above market" interest on non-qualified deferred compensation; therefore, this column reflects pension accruals only. See the discussion of the non-qualified DCP on page 34.

(5) The amounts in the "All Other Compensation" column include the following payments that we made on behalf of the Named Executives:

Name	Year	Qualified Plan 401(k) Matching Contributions ($)	Non-Qualified Plan 401(k) Matching Contributions ($)	Club Memberships ($)	Spouse Travel ($)	Total ($)
James S. Pignatelli	2008	10,350	0	1,080	2,102	13,532
Kevin P. Larson	2008	10,350	3,840	0	176	14,366
Michael J. DeConcini	2008	10,350	4,055	1,080	0	15,485
Raymond S. Heyman	2008	10,350	4,047	0	11	14,408
Karen G. Kissinger	2008	10,350	832	0	0	11,182

The "Club Memberships" and "Spouse Travel" columns include the incremental cost to the Company of such benefits. Spouse travel costs, which may include airfare and meals for the Named Executives' spouses for the annual Board retreat, and other company-related travel.

Effective January 1, 2009, Mr. Bonavia became Chairman of the Board, President and Chief Executive Officer of UniSource Energy, TEP and UES. Since Mr. Bonavia was not with the Company in 2008, he is not included as a "Named Executive" in this proxy statement. Mr. Bonavia's initial annual base salary will be $600,000. Mr. Bonavia will participate in UniSource Energy's annual cash incentive compensation program with a target award for 2009 of 80% of base salary and a maximum award equal to 120% of base salary, and will participate in the 2006 Omnibus Plan as well. Mr. Bonavia will be entitled to severance pay of 200% of his base salary, plus pro rata incentive compensation, if his employment is terminated by UniSource Energy without cause or if he terminates his employment for good reason within three years of his employment. Mr Bonavia will be entitled to a severance payment of 200% of the sum of base salary and bonus, plus pro rata incentive compensation, if UniSource Energy terminates his employment without cause or if he terminates employment for good reason within 24 months of a change in control.

GRANTS OF PLAN-BASED AWARDS—2008

The following table sets forth information regarding plan-based awards to our Named Executives in 2008. The compensation plans under which the grants in the following table were made are generally described in the "Compensation Discussion and Analysis" section, beginning on page 12 and include the UniSource Energy PEP, which provides for non-equity (cash) performance awards, and the 2006 Omnibus Plan, which provides for equity-based performance awards including stock options and performance shares.

Name	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards (2)			All Other Option Awards: Number of Securities Under-lying Options (#)(3)	Exercise or Base Price of Option Awards ($/Sh) (4)	Grant Date Fair Value of Stock and Option Awards ($)(5)
		Thresh-old ($)	Target ($)	Maxi-mum ($)	Thresh-old (#)	Target (#)	Maxi-mum (#)			
JAMES S. PIGNATELLI										
PEP	2/27/2008	290,400	580,800	871,200						
Performance Share	2/27/2008				6,680	13,360	20,040			349,765
Stock Options	2/27/2008							82,470	26.18	349,768
KEVIN P. LARSON										
PEP	2/27/2008	79,000	158,000	237,000						
Performance Share	2/27/2008				2,905	5,810	8,715			152,106
Stock Options	2/27/2008							35,890	26.18	152,215
MICHAEL J. DECONCINI										
PEP	2/27/2008	80,300	160,500	240,800						
Performance Share	2/27/2008				2,950	5,900	8,850			154,462
Stock Options	2/27/2008							36,460	26.18	154,633

Name	Grant Date	Estimated Possible Payments Under Non-Equity Incentive Plan Awards (1)			Estimated Possible Payments Under Equity Incentive Plan Awards (2)			All Other Option Awards: Number of Securities Under-lying Options (#)(3)	Exercise or Base Price of Option Awards ($/Sh) (4)	Grant Date Fair Value of Stock and Option Awards ($)(5)
		Thresh-old ($)(1)	Target ($)	Maxi-mum ($)	Thresh-old (#)	Target (#)	Maxi-mum (#)			
RAYMOND S. HEYMAN										
PEP	2/27/2008	79,000	158,000	237,000						
Performance Share	2/27/2008				2,905	5,810	8,715			152,106
Stock Options	2/27/2008							35,890	26.18	152,215
KAREN G. KISSINGER										
PEP	2/27/2008	49,800	99,600	149,400						
Performance Share	2/27/2008				2,290	4,580	6,870			119,904
Stock Options	2/27/2008							28,280	26.18	119,940

(1) The amounts shown in this column reflect the range of payouts (50%-150% of the target award) for 2008 performance under the Company's PEP, as described in the "Short-Term Incentive Compensation" section of the Compensation Discussion and Analysis above. These amounts are based on the individual's current salary and position. The amount of cash incentive actually paid under the PEP for 2008 is reflected in the Summary Compensation Table above.

(2) The amounts shown in this column reflect the range (50%-150% of the target award) of payouts in the form of performance shares targeted for 2008 performance under the 2006 Omnibus Plan for long-term incentive compensation, as described in the "Long-Term Incentive Compensation" section of the Compensation Discussion and Analysis above. The following example is an illustration of the Company's method for determining the threshold, target and maximum number of shares subject to the equity incentive awards under the long-term incentive plan. In 2008, the CEO's base salary was $726,000; therefore, the target value of the CEO's long-term incentive award was $726,000, which equaled 100% of his base salary. As described in the "Compensation Discussion and Analysis," we granted one-half of that award ($726,000/2 = $363,000) in the form of performance shares and one-half in the form of stock options. Each performance share had an initial value equal to the fair market value of one share of our common stock as of a date preceding the date of the Compensation Committee meeting at which the awards were granted ($27.17), which produced a target award of 13,360 performance shares ($363,000/$27.17= 13,360 shares). Threshold equaled 6,680 shares, which was 50% of target (13,360 * 50% = 6,680), and maximum equaled 20,040 shares, which was 150% of target (13,360 * 150% = 20,040).

(3) Stock options granted under the 2006 Omnibus Plan are described in the Outstanding Equity Awards at Fiscal Year-End Table below. Options are granted with an exercise price equal to 100% of the fair market value on the date of grant; they vest in one-third increments over a three year period and expire after 10 years. The number of stock options awarded was determined by dividing the target value of the stock option award ($363,000) by the FAS 123R

"fair value" of an option as of a date preceding the date of the Compensation Committee meeting at which the options were granted ($4.40154), resulting in a grant of 82,470 stock options ($363,000/$4.40154 = 82,471, which was rounded down to 82,470). The exercise price for each option was set at the closing price on the actual grant date.

(4) Exercise price for the February 27, 2008 stock option award was $26.18, which was the closing price of the Company's common stock on the NYSE on the grant date.

(5) This amount has been determined in accordance with FAS 123R based on the fair value of our common stock as of the grant date, which was $26.18 per share for 2008 awards.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END – 2008

The following table summarizes the number of securities underlying outstanding plan awards for each Named Executive as of December 31, 2008:

	Option Awards(1)					Stock Awards(2)	
Name	Grant Date	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Options (#) Unexer-cisable	Option Exercise Price ($)	Option Expiration Date	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)
James S. Pignatelli							
	7/16/1999	114,500		12.28	7/16/2009		
	8/3/2000	175,000		15.28	8/3/2010		
	8/2/2001	150,000		17.91	8/2/2011		
	1/2/2002	150,000		18.12	1/2/2012		
	5/9/2003	21,226		17.84	5/9/2013		
	5/5/2006	30,673	15,337	30.55	5/5/2016		
	3/20/2007	13,100	26,200	37.88	3/20/2017		
	2/27/2008		82,470	26.18	2/27/2018		
	5/5/2006					3,655	107,311
	3/20/2007					6,340	186,142
	2/27/2008					6,680	196,125

	Option Awards(1)					Stock Awards(2)	
Name	Grant Date	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Options (#) Unexer-cisable	Option Exercise Price ($)	Option Expiration Date	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)
Kevin P. Larson							
	8/3/2000	17,000		15.28	8/3/2010		
	1/2/2002	35,000		18.12	1/2/2012		
	5/9/2003	7,783		17.84	5/9/2013		
	5/5/2006	13,273	6,637	30.55	5/5/2016		
	3/20/2007	5,653	11,307	37.88	3/20/2017		
	2/27/2008		35,890	26.18	2/27/2018		
	5/5/2006					1,582	46,448
	3/20/2007					4,100	120,376
	2/27/2008					8,715	255,872
Michael J. DeConcini							
	7/16/1999	8,900		12.28	7/16/2009		
	8/3/2000	40,000		15.28	8/3/2010		
	8/2/2001	30,000		17.91	8/2/2011		
	1/2/2002	40,000		18.12	1/2/2012		
	5/9/2003	8,137		17.84	5/9/2013		
	5/5/2006	13,273	6,637	30.55	5/5/2016		
	3/20/2007	5,653	11,307	37.88	3/20/2017		
	2/27/2008		36,460	26.18	02/27/2018		
	5/5/2006					1,582	46,448
	3/20/2007					4,100	120,376
	2/27/2008					8,850	259,836

	Option Awards(1)					Stock Awards(2)	
Name	Grant Date	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Options (#) Unexer-cisable	Option Exercise Price ($)	Option Expiration Date	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)
Raymond S. Heyman							
	9/15/2005	50,000		33.55	9/15/2015		
	5/5/2006	13,273	6,637	30.55	5/5/2016		
	3/20/2007	5,653	11,307	37.88	3/20/2017		
	2/27/2008		35,890	26.18	2/27/2018		
	5/5/2006					1,582	46,448
	3/20/2007					4,100	120,376
	2/27/2008					8,715	255,872
Karen G. Kissinger							
	8/2/2001	7,000		17.91	8/2/2011		
	1/2/2002	1,152		18.12	1/2/2012		
	5/5/2006	10,526	5,264	30.55	5/5/2016		
	3/20/2007	4,466	8,934	37.88	3/20/2017		
	2/27/2008		28,280	26.18	2/27/2018		
	5/5/2006					1,254	36,817
	3/20/2007					3,240	95,126
	2/27/2008					6,870	201,703

(1) All options listed above vest at a rate of 33 1/3% per year over the first three years of the 10-year option term. The option expiration date for Mr. Pignatelli is accurate as of December 31, 2008; however, Mr. Pignatelli retired effective as of January 1, 2009 and, as a result, his options expire three years from the date of retirement or expiration date, if sooner.

(2) Performance shares vest after three years based on performance of the cumulative goals over the applicable three-year period.

(3) The amounts shown reflect the projected value of the performance share awards as of December 31, 2008. The projections regarding achievement of the performance goals were the same projections used to determine the 2008 compensation expense related to the outstanding awards for financial reporting purposes, and were done in the manner required by Financial Accounting Standards 123(R).

OPTION EXERCISES AND STOCK VESTED

The following table includes certain information with respect to the options exercised by our Named Executives during the year ended December 31, 2008:

	Option Awards	
Name	**Number of Shares Acquired on Exercise (#)(1)**	**Value Realized on Exercise ($)(2)**
James S. Pignatelli	45,096	832,510
Michael J. DeConcini	4,000	69,990

(1) Of shares exercised, the following numbers of shares were due to options that otherwise would have expired during the year: James S. Pignatelli, 45,096. Michael J. DeConcini, 4,000. Mr. DeConcini retained 4,000 of the shares acquired through the exercise of the options indicated above.

(2) For options that are exercised in cashless transactions, we base this value on the spread between the exercise price and the actual price at which the shares of common stock are sold in the market. For options that are exercised and retained by the Named Executive, we base this value on the spread between the exercise price and the actual market price of our common stock at the time of exercise.

PENSION BENEFITS

The following table shows the present value of accumulated benefits payable to each of the Named Executives, including the number of years of service credited to each such Named Executive, under each of the Retirement Plan and the Excess Benefit Plan determined using interest rate and mortality rate assumptions used in the Company's financial statements as set forth on pages 142-149 of the Company's annual report on Form 10-K. Information regarding the Retirement Plan and the Excess Benefit Plan can be found under the heading "Retirement and Other Benefits" on page 23.

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
James S. Pignatelli	Tucson Electric Power Salaried Employees Retirement Plan (1)	14.33	556,545	0
	Tucson Electric Power Excess Benefit Plan (2)	14.33	4,547,191	0
Kevin P. Larson	Tucson Electric Power Salaried Employees Retirement Plan (1)	23.83	428,588	0
	Tucson Electric Power Excess Benefit Plan (2)	23.83	403,186	0
Michael J. DeConcini	Tucson Electric Power Salaried Employees Retirement Plan (1)	20.08	236,899	0
	Tucson Electric Power Excess Benefit Plan (2)	20.08	321,025	0
Raymond S. Heyman	Tucson Electric Power Salaried Employees Retirement Plan (1)	3.33	65,112	0
	Tucson Electric Power Excess Benefit Plan (2)	3.33	216,225	0
Karen G. Kissinger	Tucson Electric Power Salaried Employees Retirement Plan (1)	18	388,618	0
	Tucson Electric Power Excess Benefit Plan (2)	18	394,263	0

(1) The Retirement Plan is intended to meet the requirements of a qualified benefit plan for Code purposes, and is funded by the Company and made available to all eligible employees. The Retirement Plan provides an annual income upon retirement based on the following formula:

1.6% x years of service (up to 25 years) x final average pay

Final average pay is calculated as the average of basic monthly earnings on the first of the month following the employee's birthday during the five consecutive plan years in which basic monthly earnings were the highest, within the last 15 plan years before retirement. Years of service are based on years and months of employment. A Retirement Plan participant is fully vested in his or her retirement benefit after five years of service. The maximum benefit available under the Retirement Plan is an annual income of 40% of final average pay (as defined above). Plan compensation for purposes of determining final average pay is limited by IRS compensation limits under Code Section 401(a)(17). For 2008, the limit was $230,000 in annual income. Employees are eligible to retire early with an unreduced pension benefit if (i) the combination of their age and years of service equals or exceeds 85 or (ii) they are age 62 and have completed 10 years of service. Employees are also eligible to early retirement with a reduced pension benefit at age 55 with at least 10 years of service. The reduction at age 55 with 10 years of service is 42.6% and continues to be reduced at a lesser amount up to age 62, where there is no reduction. All optional forms of the benefit are actuarially equivalent.

(2) The Retirement Plan is subject to Code limitations on the amount of compensation that can be taken into account and on the amount of benefits that can be provided. The Excess Benefit Plan provides the retirement benefits to officers that would have been provided under the Retirement Plan if the Code limitations did not apply. The Excess Benefit Plan retirement benefit is calculated generally using the same pension formula as the Retirement Plan formula but with some modifications. Compensation for purposes of the Excess Benefit Plan is determined without regard to IRS limits on compensation and by including voluntary salary reductions to the DCP, and any annual incentive payment received under the PEP. The retirement benefit payable from the Excess Benefit Plan is reduced by the benefit payable to that person from the Retirement Plan. Full vesting occurs after five years of service. Benefits are payable in a lump sum or annuity, at the retiree's election.

NON-QUALIFIED DEFERRED COMPENSATION

UniSource Energy sponsors the DCP for directors, officers and certain other employees of UniSource Energy. Under the DCP, employee participants are allowed to defer on a pre-tax basis up to 100% of base salary and cash bonuses and non-employee director participants are allowed to defer up to 100% of their cash compensation. This deferral plan also allows the executive employee participants to receive the 401(k) Company match that cannot be contributed to the 401(k) Plan because of limitations imposed by the Code. The deferred amounts are valued daily as if invested in one or more of a number of investment funds, including UniSource Energy stock units, each of which may appreciate or depreciate in value over time. The choice of investment funds is determined by the individual participant.

Name	Executive Contributions in Last Fiscal Year ($)(1)	Registrant Contributions in Last Fiscal Year ($)(4)	Aggregate Earnings in Last Fiscal Year ($)(2)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last Fiscal Year End ($)(3)
James S. Pignatelli	0	5,375	(266,998)	0	1,350,336
Kevin P. Larson	0	3,357	(1,210)	0	34,934
Michael J. DeConcini	0	3,357	(804)	0	24,373
Raymond S. Heyman	0	3,558	6	0	6,203
Karen G. Kissinger	0	527	(2,957)	0	59,953

(1) Represents contributions to the DCP by the Named Executives during the year. These amounts are included in the salary column of the "Summary Compensation Table" above.

(2) Represents the total market based earnings (losses) for the year on all deferred compensation under the plan based on the investment returns associated with the investment choices made by the Named Executive. Amounts in this column are not included in the "Summary Compensation Table."

(3) The amount reported for Mr. Pignatelli includes a total of $250,475 of executive contributions and registrant contributions that were reported in the Summary Compensation Table in 2006 and 2007.

(4) The amounts shown in this column reflect the actual contributions made in 2008 for the 2007 plan year.

The following table shows the deemed investment options available, and the annual rate of return for the calendar year ended December 31, 2008, under the DCP.

Name of Fund	Rate of Return	Name of Fund	Rate of Return
Fidelity Retirement Money Market	2.93%	Fidelity Spartan Us Equity Index	(37.03%)
Fidelity Intermediate Bond	(5.84%)	Fidelity Growth Company	(40.90%)
Janus Flexible Bond	5.64%	Fidelity Low Price Stock	(36.17%)
Fidelity Asset Manager	(27.80%)	Janus Worldwide	(45.02%)
Fidelity Equity-Income	(41.64%)	UniSource Energy Corporation Stock	3.67%)
Fidelity Magellan	(49.40%)		

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

Each of the Named Executives, other than Mr. Pignatelli and Mr. Heyman, are subject to a Change in Control Agreement. For the purpose of the Agreements, a "Change in Control", as defined in the Agreements, includes the acquisition of beneficial ownership of 30% of the common stock of UniSource Energy, certain changes in the Board, approval by the shareholders of certain mergers or consolidations or certain transfers of the assets of UniSource Energy. The Agreements provide that each officer shall be employed by TEP or one of its subsidiaries or affiliates, in a position comparable to his current position, with compensation and benefits, which are at least equal to his then current compensation and benefits, for an employment period of five years after a Change in Control (subject to earlier termination due to the officer's acceptance of a position with another company or termination for cause). For purposes of this section, titled "Potential Payments Upon Termination or Change in Control", only, "TEP" shall mean TEP or one of its subsidiaries or affiliates, as applicable.

The Agreements are in effect until the later of: (i) five years after the date either TEP or the officer gives written notice of termination of the Agreement, or (ii) if a Change in Control occurs during the term of the Agreements, five years after the Change in Control. On March 29, 2004, a Change in Control occurred for purposes of the Agreements when our shareholders, at a special meeting, approved the acquisition agreement that provided for an affiliate of Saguaro Utility Group L.P. to acquire all of our outstanding shares of common stock.

On March 3, 2005, TEP provided the officers of the Company with written notice of termination of the Agreements effective March 3, 2010, the fifth anniversary of the date of the written notice of termination. In December 2006, the CEO of the Company waived all rights he otherwise would have had for the remaining effective period under his Agreement and terminated the Agreement to which he and TEP had been party.

During the remaining term of the Agreements currently in effect, in the event that an officer's employment is terminated by TEP (with the exception of termination due to the officer's acceptance of another position or for cause), or if the officer terminates employment because i) there was a material change by TEP of the officer's status, title, authority, duties or responsibilities, ii) the officer was assigned or reassigned to another place of employment more than fifty miles from the officer's current place of employment, iii) a liquidation, dissolution, consolidation or merger of TEP occurred, or iv) a reduction in the officer's target compensation occurred, prior to March 29, 2009 (or within five years of any subsequent Change in Control), the officer is entitled to severance benefits in the form of: (a) a lump sum payment equal to the present value of three times the sum of annual salary and prorated target bonus ("cash severance"), (b) the present value of the additional amount (including any amount under the Excess Benefit Plan) the officer would have received under the Retirement Plan if the officer had continued to be employed for the five-year period after a Change in Control occurs, plus (c) the present value of any officer award under the 2006 Omnibus Plan or any successor plan, which is outstanding at the time of the officer's termination (whether vested or not), prorated based on length of service. Such officer is also entitled to continue to participate in TEP's health, death and disability benefit plans for five years after the termination. The Agreements further provide that TEP will make a payment to the officer to offset any golden parachute excise taxes that may be imposed in accordance with Code sections 280G and 4999. Any payments made in respect of such excise taxes are not deductible by us. Cash severance would also be paid under the Agreements if an officer dies or becomes disabled prior to March 29, 2009 (or within five years of any subsequent Change in Control).

Beginning in 2006, all long-term incentive awards contain a "double trigger" vesting provision, which provides for accelerated vesting only if outstanding awards are not assumed by an acquirer or the Named Executive is terminated without cause within 24 months of a Change in Control. The double trigger, which is viewed as a corporate governance "best practice", ensures that the Named Executives do not receive accelerated benefits unless they are adversely affected by the Change in Control.

Other than the Agreements described above, we have not entered into any other severance agreements or employment agreements with any Named Executives.

The following table and summary set forth potential payments payable to our Named Executives upon termination of employment or a Change in Control. The table below reflects amounts payable to our Named Executives assuming their employment was terminated on December 31, 2008:

Name	If Retirement or Voluntary Termination Occurs (1)	If "Change In Control" Termination Occurs ($) (2)	If Death or Disability Occurs ($) (3)
James S. Pignatelli	--	0	262,255
Kevin P. Larson	--	3,426,554	114,130
Michael J. DeConcini	--	3,169,832	115,943
Raymond S. Heyman	--	0	114,130
Karen G. Kissinger	--	2,591,663	89,930

(1) In the event of retirement or voluntary termination, each of the Named Executives would be entitled to receive vested and accrued benefits payable from the Retirement Plan and the Excess Benefit Plan, but no form or amount of any such payment would be increased or otherwise enhanced nor would vesting be accelerated with respect to such plans. In addition, no accelerated vesting of options or performance shares would occur. Retirement Plan and Excess Benefit Plan information for the Named Executives is set forth in the "Pension Benefits Table" above. Mr. Heyman is not vested in the retirement plans as of December 31, 2008.

(2) In December 2006, James S. Pignatelli waived all rights under his Agreement and terminated the Agreement to which he and TEP had been party. Mr. Heyman does not have an Agreement. The breakout of the above referenced elements for the three Named Executives is as follows:

Named Executive	Cash ($)	Prorated Bonus ($)	Stock Options ($)	Performance Shares ($)	Medical Benefits ($)	Retirement Benefits ($)	Tax Gross-up ($)	Total ($)
Kevin P. Larson	1,422,000	158,000	114,130	290,958	73,906	462,888	904,673	3,426,554
Michael J. DeConcini	1,444,500	160,500	115,943	293,600	82,756	213,264	859,269	3,169,832
Karen Kissinger	1,045,800	99,600	89,930	229,595	82,567	402,732	641,438	2,591,663

(3) Amounts in this column reflect the value of all unvested options that would accelerate upon the death or disability of the Named Executives. There is no acceleration of performance shares. In addition, in the event of death, the Named Executive's survivor would be entitled to receive a death benefit in the form of a lump sum or survivor annuity which is funded from the Retirement Plan and Excess Benefit Plan. The amount payable to the survivor would be less than the amount that would otherwise have been payable to the Named Executive had the Named Executive survived and received retirement benefits under the Retirement Plan and Excess Benefit Plan. There would be no enhancements as to form, amount or vesting of such benefits in the event of a Named Executive's death.

DIRECTOR COMPENSATION

For 2008, our non-employee directors received the following compensation:

1. Annual cash retainer of $40,000, paid in monthly installments.
2. Additional annual cash retainer of $20,000 for the Lead Director, $10,000 for the Audit Chair, $7,500 for each of the Compensation and Corporate Governance Chairs, and $5,000 for all other committee chairs, all of which are paid in quarterly installments.
3. Board and committee meeting fees of $1,000 per meeting.
4. Annual award of $45,000 in restricted stock units:
    - Directors serving on the date of the Annual Shareholders' meeting receive a grant on the date of that meeting. Any person who first becomes a director after the Annual Shareholders' meeting receives a grant on a date approved by the Compensation Committee. All restricted stock unit grants to directors vest at the earlier of the next annual meeting following grant date or the first anniversary of grant.
    - The actual number of restricted stock units granted is calculated by dividing $45,000 by the closing price of our common stock on the date of grant.
    - Vested stock units must be deferred and distributed in January of the year following the year during which a director ceases to serve as a member of our Board. Deferred stock units accrue dividend equivalents during the deferral period. Deferred stock units will be distributed in shares of Company stock.

Mr. Pignatelli, our CEO during 2008, did not receive any additional compensation for serving as a director. Directors may elect to defer cash fees and retainers under the DCP, which is described on page 23.

In 2007, we adopted formal stock ownership guidelines for our non-employee directors. Non-employee directors are expected to accumulate Company shares with a value equal to 500% of the annual equity grant. Shares owned outright, including shares held in street name accounts, jointly with spouse, or in trust for the non-employee director's benefit, and deferred stock units count towards meeting the guideline.

The following table summarizes the compensation earned by non-employee directors of the Company for the year ended December 31, 2008.

Name (1)	Fees Earned or Paid in Cash ($)(2)	Stock Awards ($) (3)(4)(5)	All Other Compensation ($)(6)	Total ($)
Lawrence J. Aldrich	73,000	46,875	5,014	124,889
Barbara M. Baumann	83,000	46,875	3,982	133,857
Larry W. Bickle	73,333	46,875	10,621	130,829
Elizabeth T. Bilby	72,000	46,875	7,009	125,884
Harold W. Burlingame(8)	97,500	46,875	10,339	154,714
John L. Carter(8)	120,000	46,875	4,826	171,701
Robert A. Elliott(8)	97,500	46,875	3,637	148,012
Daniel W. L. Fessler(8)	87,000	125,250	5,894	218,144
Louise L. Francesconi(7)	31,666	16,875	611	49,152
Kenneth Handy	75,000	46,875	5,429	127,304
Warren Y. Jobe(8)	94,000	46,875	9,303	150,178
Ramiro G. Peru	73,000	69,375	591	142,966
Gregory A. Pivirotto	71,000	69,375	316	140,691
Joaquin Ruiz	73,666	46,875	3,424	123,965

(1) Mr. Pignatelli is not included in this table, as he is an employee of the Company and thus receives no compensation for his service as a director. The compensation received by Mr. Pignatelli as an employee of the Company is shown in the "Summary Compensation Table."

(2) Lawrence J. Aldrich, Barbara M. Baumann, Harold W. Burlingame, Kenneth Handy and Joaquin Ruiz, deferred 100% of fees earned in 2008 into the DCP.

(3) Each non-employee director received an annual restricted stock unit award valued at $45,000 in 2008. Values reflected in the table are consistent with FAS 123R grant date fair value and include amortization of a portion of a May 2007, June 2007, February 2008, May 2008 and August 2008 awards. This amount disregards estimates of forfeitures related to service based vesting conditions. Each of the directors in office on May 2, 2008 was awarded 1,419.1 restricted stock units at a fair market value share price of $31.71. On February 11, 2008, Mr. Peru and Mr. Pivirotto were each awarded 1,565.2 restricted stock units at a fair market value share price of $28.75. On August 14, 2008, Mrs. Francesconi was awarded 1,399.7 restricted stock units at a fair market value of $32.15. After a one year vesting period the restricted stock units convert to deferred stock units and are payable in January that follows the calendar year in which the director ceases to be a Board member. The award price for the annual director equity award was the closing price on the date of grant.

The values reflected in this column for Mr. Fessler also reflect the 2008 expense attributable to the restricted stock units granted in May of 2007. In May 2007, the Compensation Committee approved a grant of 4,902.5 restricted stock units to Mr. Fessler. Mr. Fessler served as a director on the Board from 1998 to 2003. In 2005, Mr. Fessler rejoined the Board as a director. Upon Mr. Fessler's initial retirement from the Board in 2003, Mr. Fessler had 7,201 vested stock options outstanding under the 1994 Outside Directors Stock Option Plan. At the time of his retirement, UniSource Energy mistakenly informed Mr. Fessler that the options would expire at the end of their original terms. However, under the terms of the plan, the options expired six months after his retirement. In reliance on the mistaken information, Mr. Fessler failed to exercise the options prior to their expiration. The grant in May 2007 was in an amount intended to restore Mr. Fessler to the position he would have been in had he exercised the options at the end of the six month period after his retirement and held the stock received upon such exercise through the date of the May 2007 award.

(4) As of December 31, 2008 the unvested stock units held by directors were as follows: Mr. Aldrich held 1,419 stock units; Mrs. Baumann held 1,419 stock units; Mr. Bickle held 1,419 stock units; Mrs. Bilby held 1,419 stock units; Mr. Burlingame held 1,419 stock units; Mr. Carter held 1,419 stock units; Mr. Elliott held 1,419 stock units; Mr. Fessler held 1,419 stock units; Mr. Handy held 1,419 stock units; Mr. Jobe held 1,419 stock units; Mr. Ruiz held 1,419 stock units; Mr. Pivirotto held 1,419 stock units; Mr. Peru held 1,419 stock units; and Ms. Francesconi held 1,400 stock units.

(5) As of December 31, 2008 all stock options are vested and are reported in the Security Ownership of Management table on pages 6-7.

(6) Amounts represent the value of dividend equivalents associated with restricted stock units and stock option awards held by the directors, expensed in accordance with FAS 123R. The amounts also include reimbursement to the applicable directors for travel expenses incurred by their respective spouses in attending the annual meeting dinner, the board retreat and/or the holiday dinner and a tax gross-up with respect to the reimbursement.

(7) Ms. Francesconi was appointed to the Board, effective August 14, 2008, which is reflected in her compensation for 2008.

(8) The directors noted were members of the Corporate Development Committee during 2008, which is discussed under the "Board Committees" section below. These directors received compensation for attending meetings of the Corporate Development Committee consistent with the compensation parameters set forth under "Director Compensation" on page 37. The compensation for each of the noted directors is greater than the compensation shown for the other directors due to the number of meetings held by the Corporate Development Committee in 2008.

EQUITY COMPENSATION PLAN INFORMATION

Equity Compensation Plans

Our only equity-based compensation plan that has not been approved by shareholders is the DCP. Shareholder approval of the DCP has not been required because the provisions of the DCP permit the Company to payout deferred shares accumulated under the DCP in the form of cash or stock. Under the terms of the plan, distribution of deferred shares will be made in cash, unless the participant elects to receive the deferred shares in Company stock. Under the DCP, certain eligible officers and other employees selected for participation, and non-employee members of the Board, may elect to defer a percentage of the compensation or fees that would otherwise become payable to the individual for his services to us. We also credit DCP accounts of employees participating in our 401(k) Plan with the additional amount of UniSource Energy matching contributions that the participant would have been entitled to under the 401(k) Plan if certain Code limits did not apply to limit the amount of UniSource Energy matching contributions made under the 401(k) Plan. Each participant in the DCP may elect that his deferrals be credited in the form of deferred shares instead of cash. Deferred shares accrue dividend equivalents, credited in the form of additional deferred shares, as dividends are paid by UniSource Energy on its issued and outstanding common stock. Each participant elects the time and manner of payment (lump sum or installments) of his deferred shares under the DCP.

Equity Compensation

The following table sets forth information as of December 31, 2008, with respect to UniSource Energy's equity compensation plans.

Plan Category	Number of Shares of UniSource Energy Common Stock to be Issued Upon Exercise of Outstanding Options and Rights	Weighted-Average Exercise Price of Outstanding Options	Number of Shares of UniSource Energy Common Stock Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Shares Reflected in the First Column)
Equity Compensation Plans Approved by Shareholders (1)	2,012,120 (2)	$22.49583 (3)	1,392,860 (1)
Equity Compensation Plans Not Approved by Shareholders	84,190 (4)	--	-- (5)
Total	2,096,310	--	--

(1) The equity compensation plans that have been approved by shareholders are the UniSource Energy Corporation 1994 Omnibus Stock and Incentive Plan ("1994 Stock and Incentive Plan"), the UniSource Energy Corporation 1994 Outside Director Stock Option Plan (the "1994 Directors Plan") and the 2006 Omnibus Plan. Awards were made under the 1994 Stock and Incentive Plan and the 1994 Directors Plan until February 2004 at which time no further awards could be made under those plans. In May 2006, the 2006 Omnibus Plan was approved by shareholders and includes awards in the form of options, restricted stock, stock units and dividend equivalents. While the 1994 plans expired in February 2004 and no further awards could be made under those plans after that date, the 1994 plans remain in effect with respect to previous awards until all awards have expired or terminated or shall have been exercised or fully vested, and any stock thereto shall have been purchased or acquired. No shares that were available to be issued under the 1994 Directors Plan at the time of its termination are available for awards under the 2006 Omnibus Plan with respect to awards that are forfeited, terminated, canceled or expired.

(2) Includes options outstanding as to 1,634,627 shares, stock units, dividend equivalent stock units and restricted stock units (payable in an equivalent number of shares) outstanding as to 377,493 shares.

(3) Calculated based on the outstanding options and exclusive of outstanding stock units.

(4) Deferred shares credited under the DCP.

(5) There is no explicit share limit under the DCP. The number of shares to be delivered with respect to the DCP in the future depends on the levels of fees and compensation that participants elect to defer under the DCP. Any UniSource Energy shares used to satisfy our common stock obligations under the DCP will be shares that have been purchased on the open market.

CORPORATE GOVERNANCE

Board Meetings

In 2008, the Board held a total of eight regular and special meetings. Each director attended at least 95% of the aggregate total number of Board meetings and meetings of committees of which they are a member. Additionally, the non-management Directors met at regularly scheduled executive sessions without management present. Mr. Carter, a non-management director, presided over and was the Lead Director at these executive sessions.

The Company does not have a formal policy with respect to attendance of Board members at annual meetings of shareholders, but encourages such attendance. All of the Board members holding office at the time attended the 2008 Annual Meeting.

Board Communication

Shareholders or other interested parties wishing to communicate with the Board, the non-management directors or any individual director may contact the Lead Director by mail, addressed to UniSource Energy Lead Director, c/o Corporate Secretary, UniSource Energy Corporation, One South Church Avenue, Suite 1820, Tucson, Arizona 85701. The communications will be kept confidential and forwarded to the Lead Director. Communications received by the Lead Director will be forwarded to the appropriate director(s) or to an individual non-management director.

Shareholders or other interested parties wishing to communicate with the Board regarding non-financial matters may contact the Chairperson of the Corporate Governance and Nominating Committee either by mail, addressed to Chairperson, Corporate Governance and Nominating Committee, UniSource Energy Corporation, P.O. Box 31771, Tucson, Arizona 85751-1771, or by e-mail at unscorpgov@earthlink.net. Shareholders or other interested parties wishing to communicate with the Board regarding financial matters may contact the Chairperson of the Audit Committee either by mail, addressed to Chairperson, Audit Committee, UniSource Energy Corporation, P.O. Box 46093, Denver, Colorado 80201, or by e-mail at unscorpaudit@earthlink.net.

Items that are unrelated to a director's duties and responsibilities as a Board member may be excluded from consideration, including, without limitation, solicitations and advertisements, junk mail, product-related communications, job referral materials such as resumes, surveys and material that is determined to be illegal or otherwise inappropriate.

DIRECTOR INDEPENDENCE CRITERIA

The Board has adopted Director Independence Standards to comply with NYSE rules for determining independence, among other things, in order to determine eligibility to serve on the Audit Committee, the Compensation Committee and the Corporate Governance and Nominating Committee. The Director Independence Standards, amended as of February 9, 2007, are available on our website at www.UNS.com and are available in print to any shareholder who requests it.

No director may be deemed independent unless the Board affirmatively determines, after due deliberation, that the director has no material relationship with the Company either directly or as a partner, shareholder or officer of an organization that has a relationship with the Company. In each case, the Board broadly considers all the relevant facts and circumstances from the standpoint of the director as well as from that of persons or organizations with which the director has an affiliation and applies these standards.

Annually, the Board determines whether each director meets the criteria of independence. Based upon the foregoing criteria, the Board has deemed each director to be independent, with the exception of Mr. Pignatelli (who retired effective as of January 1, 2009), Ms. Bilby and Mr. Bonavia (who became the new Chief Executive Officer effective January 1, 2009). For each other director who is deemed independent, there were no other significant transactions, relationships or arrangements that were considered by the Board in determining that the director is independent. See "Transactions with Related Persons" on page 45.

Board Committees

Corporate Governance and Nominating Committee

The Corporate Governance and Nominating Committees operates under the provisions of a committee charter. The Corporate Governance and Nominating Committee reviews and recommends corporate governance principles, interviews potential directors and nominates and recommends to the shareholders and directors, as the case may be, qualified persons to serve as directors. The Corporate Governance and Nominating Committee also reviews and recommends membership for all the committees to the Board and reviews applicable rules and regulations relating to the duties and responsibilities of the Board. Our Corporate Governance and Nominating Committee held three meetings in 2008 and was in compliance with its written charter.

The Corporate Governance and Nominating Committee identifies and considers candidates supplied by shareholders and Board members. The Corporate Secretary, as directed by the Corporate Governance and Nominating Committee, prepares portfolios for candidates that include confirmation of the candidate's interest, independence, biographical information, review of business background and experience and reference checks. The Corporate Governance and Nominating Committee then evaluates candidates using, in large part, the criteria set forth in the next paragraph and any other criteria the Corporate Governance and Nominating Committee deems appropriate, and conducts a personal interview with each candidate. Upon completion of this process, formal invitations are extended to accept election to the Board.

The Corporate Governance and Nominating Committee has not adopted specific minimum qualifications with respect to a committee-recommended Board nominee, but desirable qualifications are set forth in the Corporate Governance Guidelines and include prior community, professional or business experience that demonstrates leadership capabilities, the ability to review and analyze complex business issues, the ability to effectively represent the interests of our shareholders while keeping in perspective the interests of our customers, the ability to devote the time and interest required to attend and fully prepare for all regular and special Board meetings, the ability to communicate and work effectively with the other Board members and personnel and the ability to fully adhere to any applicable laws, rules or regulations relating to the performance of a director's duties and responsibilities.

While no formal policy exists, the Corporate Governance and Nominating Committee does consider recommendations for Board nominees received from our shareholders. The deadline for consideration of recommendations for next year's annual meeting of the shareholders is November 21, 2009. Recommendations must be in writing and include detailed biographical material indicating the candidate's qualifications and a written statement from the candidate of his willingness and availability to serve. Recommendations should be directed to the Corporate Secretary, UniSource Energy Corporation, One South Church Avenue, Suite 1820, Tucson, Arizona 85701. The Board will consider nominees on a case-by-case basis and does not believe a formal policy is warranted at this time due to a manageable volume of nominations.

Each member of our Audit Committee, Compensation Committee and Corporate Governance and Nominating Committee is independent based upon independence criteria established by our Board, which criteria are in compliance with applicable NYSE listing standards.

Compensation Committee

The Compensation Committee operates under the provisions of a committee charter, which was amended most recently in November 2007. The Compensation Committee Charter can be revised by action taken by the Compensation Committee. Under the terms of its charter, the Compensation Committee is required to consist of not fewer than three members of the Board who meet the independence requirements of the NYSE. In 2008, the Compensation Committee had six members who met those independence requirements.

In 2008, the Compensation Committee held five formal meetings, most of which were followed by an executive session in which management did not participate. The Compensation Committee Chair sets the agenda for each meeting, and in advance of each meeting reviews the agenda with management. The annual schedule of meetings is approved by the Board during the fourth quarter for the following year. In connection with Compensation Committee meetings, each Compensation Committee member receives a briefing book prior to each meeting that details each topic to be considered. The Compensation Committee Chair reports to the Board on Compensation Committee decisions and key actions following each meeting. The Compensation Committee members also complete a written assessment of the Compensation Committee's performance, with the last such assessment completed in September 2008.

The Board has delegated authority to the Compensation Committee to set CEO compensation levels, and to review and approve compensation for all of the Company's executives, including any equity compensation awarded under the 2006 Omnibus Plan. Under the terms of its charter, the Compensation Committee may delegate certain actions to management of the Company in connection with executive compensation. Day-to-day administration of director and executive compensation matters has been delegated to certain Company management personnel, with oversight provided by the Compensation Committee.

Compensation Consultant

The Compensation Committee has retained the services of Frederic W. Cook and Co., Inc. ("Cook"), a nationally recognized compensation consulting firm that serves as an independent advisor in matters related to executive compensation and non-employee director compensation. Representatives from Cook are available to Compensation Committee members on an ongoing basis and attend Compensation Committee meetings, as requested, either in person or telephonically. The Compensation Committee has sole discretion over the terms and conditions of the retention of consultants it retains. Cook maintains no other economic relations with the Company and does not provide any services to the Company other than those provided directly to the Compensation Committee.

The Compensation Committee Chair customarily provides assignments to Cook. In its role as executive compensation consultant to the Compensation Committee, Cook assists with peer group selection, the benchmarking of individual compensation levels, and the design of incentive plans and other compensation arrangements in which Company management participates. In furnishing this assistance, Cook provides competitive data and technical considerations, and recommends changes to the pay program and pay levels for consideration by the Compensation Committee.

Role of Executives in Establishing Compensation

Certain executives, including the CEO, the CFO and the General Counsel to the Company, routinely attend regular sessions of Compensation Committee meetings. The CEO makes recommendations to the Compensation Committee with respect to changes in compensation for senior executive positions (other than the CEO) and payouts under the annual incentive plan. The CEO also makes suggestions to the Compensation Committee regarding the design of incentive plans and other programs in which senior management participates.

The CFO provides information regarding short-term and long-term compensation targets, as well as updates on the progress of short- and long-term objectives. Additional Company personnel with expertise in and responsibility for compensation and benefits provide information regarding executive and director compensation, including cash compensation, equity awards, pensions, deferred compensation and other related information.

Audit Committee

The Audit Committee operates under the provisions of a committee charter. The Audit Committee reviews current and projected financial results of operations, selects a firm of independent registered public accountants to audit our financial statements annually, reviews and discusses the scope of such audit, receives and reviews the audit reports and recommendations, transmits its recommendations to the Board, reviews our accounting and internal control procedures with our internal audit department from time to time, makes recommendations to the Board for any changes deemed necessary in such procedures and performs such other functions as delegated by the Board. Our Audit Committee held six meetings in 2008 and was in compliance with its written charter, as amended in December 2007.

Upon the recommendation of the Audit Committee, our Board adopted a Code of Ethics for our directors, officers and employees.

Finance Committee

The Finance Committee reviews and recommends to the Board long-range financial policies, objectives and actions required to achieve those objectives. Specifically, the Finance Committee reviews capital and operating budgets, current and projected financial results of operations, short-term and long-range financing plans, dividend policy, risk management activities and major commercial banking, investment banking, financial consulting and other financial relations of UniSource Energy. Our Finance Committee held six meetings in 2008 and was in compliance with its written charter.

Environmental, Safety and Security ("ESS") Committee

The ESS Committee reviews the Company's structure and operations to assess whether significant operating risks in the areas of environmental, safety and security have been identified and appropriate mitigation plans have been implemented. The ESS Committee also reviews the processes in place which are designed to ensure compliance with all environmental, safety and security related legal and regulatory requirements, as well as reviews with management the impact of proposed or enacted laws or regulations related to environmental, safety and security issues. Our ESS Committee held three meetings in 2008 and was in compliance with its written charter.

Corporate Development Committee

The Corporate Development Committee was created in 2008 for the purpose of working on executive development and selecting a successor Chief Executive Officer for the Company. The Corporate Development Committee held 15 meetings in 2008. The Corporate Development Committee did not operate under the provisions of a charter and terminated at the end of 2008 following the hiring of the new Chief Executive Officer for the Company.

Compensation Committee Interlocks and Insider Participation

All members of the Compensation Committee during fiscal year 2008 were independent directors, and no member was an employee or former employee. No Compensation Committee member had any relationship requiring disclosure under "Transactions with Related Persons" on page 45. During fiscal year 2008, none of our executive officers served on the compensation committee (or its equivalent) or board of directors of another entity whose executive officer(s) served on our Compensation Committee, any other Board committee, or the Board of Directors as a whole.

Copies of Charters, Guidelines and Code of Ethics

A copy of the current Audit, Compensation, Finance and Corporate Governance and Nominating Committee Charters, as well as our Corporate Governance Guidelines and Code of Ethics, together with any amendments, are available on our Web site at www.UNS.com or may be obtained by shareholders, without charge, upon written request to Library and Resource Center, UniSource Energy Corporation, 3950 East Irvington Road, Mail Stop RC114, Tucson, Arizona 85714.

TRANSACTIONS WITH RELATED PERSONS

Related Person Transactions Policy

In February 2007, the Board adopted a written policy on the review of related person transactions (which is available on our website at www.UNS.com) that specifies that certain transactions involving directors, nominees, executive officers, significant shareholders and certain other related persons in which the Company is or will be a participant and are of the type required to be reported as a related person transaction under Item 404 of Regulation S-K shall be reviewed by the Audit Committee for the purpose of determining whether such transactions are in the best interest of the Company. The policy also establishes a requirement for directors, nominees and executive officers to report transactions involving a related party that exceeds $120,000 in value. We are not aware of any transactions entered into since adoption of the policy that did not follow the procedures outlined in the policy.

On January 29, 2008, the son of one of our directors, Ms. Bilby, was appointed as Chief Financial Officer of Global Solar Energy ("GSE"). GSE had been one of our subsidiaries prior to our sale of GSE in 2006. In connection with the sale of GSE, GSE entered into a lease with our subsidiary Millennium Energy Holdings ("MEH") for the building comprising GSE's manufacturing facility. The lease terminated in September of 2008. The aggregate amount of lease payments made by GSE to MEH in 2008 was $280,000. Ms. Bilby's son had no monetary interest in the lease transaction.

AUDIT COMMITTEE REPORT

The Committee

The Audit Committee is made up of five financially literate directors who are independent based upon independence criteria established by our Board, which criteria are in compliance with applicable NYSE listing standards. Our Board has determined that while each member of the Audit Committee has accounting and/or related financial management expertise, Ms. Baumann is the Audit Committee financial expert for the purposes of Item 407(d)(5) of SEC Regulation S-K. In addition to Ms. Baumann, there are three other financial experts on the Audit Committee. Each financial expert is independent as that term is used in Item 7(d)(3)(iv) of Schedule 14A under the Securities Exchange Act of 1934, as amended. The Board previously adopted a written charter for the Audit Committee. The Audit Committee has complied with its charter, including the requirement to meet periodically with our Independent Registered Public Accounting Firm, internal audit department and management to discuss the auditor's findings and other financial and accounting matters.

In connection with our December 31, 2008 financial statements, the Audit Committee has: (i) reviewed and discussed the audited financial statements with management, (ii) discussed with PricewaterhouseCoopers, LLP, our Independent Registered Public Accounting Firm, the matters required to be discussed by Statement on Auditing Standards No. 61, as amended (AIPCA, Professional Standards, Vol. 1 AU Sec. 380), as adopted by the Public Company Accounting Oversight Board in Rule 3200T, (iii) received from PricewaterhouseCoopers, LLP, the written disclosures and the letter required by applicable requirements of the Public Accounting Oversights Board regarding the Independent Registered Public Accounting Firm's communications with the Audit Committee concerning independence, and (iv) discussed with PricewaterhouseCoopers, LLP its independence.

Based on the review and discussions referred to in items (i) through (iv) of the above paragraph, the Audit Committee recommended to the Board that the audited financial statements for 2008 be included in the annual report on Form 10-K for filing with the SEC.

Pre-Approved Policies and Procedures

Rules adopted by the SEC in order to implement requirements of the Sarbanes-Oxley Act of 2002 require public company audit committees to pre-approve audit and non-audit services. Our Audit Committee has adopted a policy pursuant to which audit, audit-related, tax and other services are pre-approved by category of service. Recognizing that situations may arise where it is in our best interest for the auditor to perform services in addition to the annual audit of our financial statements, the policy sets forth guidelines and procedures with respect to approval of the four categories of service designed to achieve the continued independence of the auditor when it is retained to perform such services for us. The policy requires the Audit Committee to be informed of each service and does not include any delegation of the Audit Committee's responsibilities to management. The Audit Committee may delegate to the Chairman of the Audit Committee the authority to grant pre-approvals of audit and non-audit services requiring Audit Committee approval where the Audit Committee Chairman believes it is desirable to pre-approve such services prior to the next regularly scheduled Audit Committee meeting. The decisions of the Audit Committee Chairman to pre-approve any such services from one regularly scheduled Audit Committee meeting to the next shall be reported to the Audit Committee.

Fees

The following table details fees paid to PricewaterhouseCoopers, LLP for professional services during 2007 and 2008. The Audit Committee has considered whether the provision of services to us by PricewaterhouseCoopers, LLP, beyond those rendered in connection with their audit and review of our financial statements, is compatible with maintaining their independence as auditor.

	2008	2007
Audit Fees	$ 1,692,707	$1,627,888
Audit-Related Fees	$ 50,000	$ 47,500
Tax Fees	$ 0	$ 0
All Other Fees	$ 4,500	$ 3,690
Total	$ 1,747,207	$1,679,078

Audit fees include fees for the audit of our consolidated financial statements included in our annual report on Form 10-K and review of financial statements included in our Quarterly Reports on Form 10-Q. Audit fees also include services provided by PricewaterhouseCoopers, LLP in connection with the audit of the effectiveness of internal control over financial reporting and on management's assessment of the effectiveness of internal control over financial reporting, comfort letters, consents and other services related to SEC matters and financing transactions, statutory and regulatory audits, and accounting consultations to the extent necessary for PricewaterhouseCoopers, LLP to fulfill their responsibilities under generally accepted auditing standards.

Audit-related fees during 2008 and 2007 principally include fees for employee benefit plan audits.

No tax fees, which in the past have included fees for tax compliance, tax advice and tax planning, were incurred during 2007 or 2008.

All other fees consist of fees for all other services other than those reported above and, in 2007 and 2008, principally include subscription fees for research tools and attendance at training courses.

All services performed by PricewaterhouseCoopers, LLP are approved in advance by the Audit Committee in accordance with the Audit Committee's pre-approval policy for services provided by the Independent Registered Public Accounting Firm.

Respectfully submitted,

THE AUDIT COMMITTEE

Barbara M. Baumann, Chair
John L. Carter
Daniel W. L. Fessler
Warren Y. Jobe
Gregory A. Pivirotto

SUBMISSION OF SHAREHOLDER PROPOSALS

General

Rule 14a-4 of the SEC's proxy rules allows us to use discretionary voting authority to vote on a matter coming before an annual meeting of our shareholders, which was not included in our Proxy Statement (if we do not have notice of the matter at least 45 days before the date on which we first mailed our proxy materials for the prior year's annual meeting of the shareholders). In addition, we may also use discretionary voting authority if we receive timely notice of such matter (as described in the preceding sentence) and if, in the Proxy Statement, we describe the nature of such matter and how we intend to exercise our discretion to vote on it. Accordingly, for our 2010 annual meeting of shareholders, any such notice must be submitted to the Corporate Secretary of UniSource Energy, One South Church Avenue, Suite 1820, Tucson, Arizona, 85701, on or before February 10, 2010.

We must receive your shareholder proposals by November 21, 2009.

This requirement is separate and apart from the SEC's requirements that a shareholder must meet in order to have a shareholder proposal included in our Proxy Statement. Shareholder proposals intended to be presented at our 2010 annual meeting of the shareholders must be received by us no later than November 21, 2009 in order to be eligible for inclusion in our Proxy Statement and the form of proxy relating to that meeting. Direct any proposals, as well as related questions, to the undersigned.

DELIVERY OF PROXY MATERIALS TO HOUSEHOLDS

If you and one or more shareholders of Company stock share the same address, it is possible that only one Notice of Internet Availability of Proxy Materials was delivered to your address. This is known as "householding." Any registered shareholder who wishes to receive separate copies of the Notice of Internet Availability of Proxy Materials at the same address now or in the future may call or write the Company's Stock Transfer Agent, BNY/Mellon, toll free at 1-866-537-8709/or BNY Shareowner Services, 480 Washington Blvd – 29th Floor, Jersey City, NJ, 07310. Separate copies of the Notice of Internet Availability of Proxy Materials will be promptly delivered upon receipt of such request.

Shareholders who own Company stock through a broker and who wish to receive separate copies of the Notice of Internet Availability of Proxy Materials should contact their broker.

Any registered shareholder who wishes to receive a single copy of the Notice of Internet Availability of Proxy Materials at the same address now or in the future may call the Company's Stock Transfer Agent, BNY/Mellon, toll free at 1-866-537-8709.

OTHER BUSINESS

The Board knows of no other matters for consideration at the Meeting. If any other business should properly arise, the persons appointed in the enclosed proxy have discretionary authority to vote in accordance with their best judgment.

Copies of our annual report on Form 10-K may be obtained by shareholders, without charge, upon written request to the Library and Resource Center, UniSource Energy Corporation, 3950 East Irvington Road, Mail Stop RC114, Tucson, Arizona 85714. You may also obtain our SEC filings through the Internet at www.sec.gov or www.UNS.com.

By order of the Board of Directors,

Linda Kennedy

Linda H. Kennedy
Corporate Secretary

PLEASE VOTE - YOUR VOTE IS IMPORTANT

UNS GAS, INC.'S RESPONSE TO RUCO'S FIRST SET OF DATA REQUESTS DOCKET NO. G-04204A-08-0571 May 7, 2009

RUCO 1.94 Identify the amount of fleet fuel expense in the test year and for each of the calendar years 2006, 2007 and 2008. Identify the current cost of fleet fuel as well as the cost of fleet fuel used to calculate fleet expense in the test year.

RESPONSE: Please see the Excel files RUCO 1.94 Test Year, RUCO 1.94 2006, RUCO 1.94 2007 and RUCO 1.94 2008 on the enclosed CD for the amount of fleet fuel expense for the test year, 2006, 2007 and 2008, respectively. The current cost of fleet fuel as of 5-6-09 is an average of $2.09/gallon.

The Excel Files are <u>not</u> identified by Bates numbers.

RESPONDENT: Julie Gomez

WITNESS: Dallas Dukes

SUPPLEMENTAL RESPONSE: The "Miles" column in the Excel file RUCO 1.94 2006 was left blank when submitted to RUCO, without explanation. The reason this column is blank is that in 2006 the UNS Gas vehicles had not been fully loaded into the Tucson Electric Power Fleet Management system. UNS Gas is unable to give an accurate mileage account for 2006. The miles traveled in 2007 should be close to what was traveled in 2006.

RESPONDENT: Gary Kelly

WITNESS: Dallas Dukes

UNS GAS, INC.
CALENDAR YEAR 2006

Source: J. Gomez

Month	Amount	$/Gal	Gallons	Miles
Jan-06	$51,607.67	$2.51	20,562	
Feb-06	$41,820.39	$2.51	16,694	
Mar-06	$48,541.12	$2.59	18,731	
Apr-06	$52,119.78	$2.94	17,743	
May-06	$59,700.07	$3.13	19,073	
Jun-06	$55,163.42	$3.02	18,290	
Jul-06	$56,249.17	$3.01	18,709	
Aug-06	$58,787.62	$2.98	19,698	
Sep-06	$50,196.41	$2.67	18,828	
Oct-06	$42,975.81	$2.45	17,542	
Nov-06	$50,686.13	$3.06	16,567	
Dec-06	$31,243.89	$2.50	12,498	
Totals		$2.78	214,935	0

UNS GAS, INC.
CALENDAR YEAR 2007

Source: J. Gomez

Month	Amount	$/Gal	Gallons	Miles
Jan-07	$45,492.84	$2.42	18,777	287,170
Feb-07	$41,837.05	$2.47	16,937	286,775
Mar-07	$53,673.60	$2.74	19,618	315,877
Apr-07	$53,321.43	$2.99	17,833	332,610
May-07	$58,540.21	$3.09	18,946	273,648
Jun-07	$56,211.24	$3.07	18,310	357,882
Jul-07	$60,051.97	$2.99	20,070	310,803
Aug-07	$55,347.52	$2.84	19,460	352,954
Sep-07	$49,526.26	$2.84	17,468	281,905
Oct-07	$55,776.30	$2.99	18,625	299,792
Nov-07	$55,464.72	$3.25	17,086	328,348
Dec-07	$50,490.71	$3.21	15,717	179,787
Totals		**$2.91**	**218,847**	**3,607,551**

Month	Amount	$/Gal	Gallons	Miles
Jan-08	$70,175.96	$3.16	22,234	216,237
Feb-08	$60,357.91	$3.25	18,597	220,381
Mar-08	$64,770.37	$3.56	18,173	207,156
Apr-08	$70,034.64	$3.72	18,840	178,971
May-08	$76,492.80	$4.04	18,942	200,136
Jun-08	$63,602.51	$4.33	14,687	183,716
Jul-08	$80,189.92	$4.30	18,641	171416
Aug-08	$70,220.72	$3.96	17,712	210901
Sep-08	$67,637.02	$3.77	17,924	166329
Oct-08	$59,430.74	$3.24	18,345	217413
Nov-08	$38,344.82	$2.50	15,368	147355
Dec-08	$27,617.38	$2.03	13,611	194943
Totals		**$3.49**	**213,074**	**2,314,954**

Tribune
EAST VALLEY • SCOTTSDALE

May 19, 2009

Gas prices on the rise for summer driving

By Edward Gately
Tribune

Mesa resident James Lowery fills up at Mobil on Baseline and Stapley Roads in Mesa.

Tribune

The past week's jump in gas prices no doubt has many East Valley motorists fearing another price escalation is on its way this summer.

However, prices aren't likely to match last summer's record-setting climb, said Michelle Donati, AAA Arizona spokeswoman. The current statewide average for a gallon of regular unleaded gas is $2.10, an increase of about 18 cents over the past month, she said.

"However, we are still paying $1.48 less per gallon than we were paying this time last year," she said.

The price increase can be attributed in part to the transition to the summer fuel blend, which is cleaner burning and more expensive to produce, Donati said. Also, oil prices have increased from the low $50s range for a barrel to the high $50s range for a barrel, she said.

"Those increased crude costs have resulted in higher wholesale costs for gasoline, which has had an adverse effect on retail margins, so all of that trickles down to higher pump prices for consumers," she said.

Last year when prices were reaching $4 a gallon and beyond, crude oil was trading at more than double what it is now, Donati said.

In the meantime, Arizona continues to have the lowest gas prices in the country, she said.

Nationally, gas prices could hit $2.50 a gallon this summer, said Tom Kloza, publisher and chief oil analyst at Oil Price Information Service.

"I think that the average price in the country will soon flirt with $2.40 a gallon, which is higher than what I projected through the first four months of this year," he said. "I think that those average prices may even flirt with $2.50 a gallon, but that would be quite frothy. It would shock me if we see prices in any metropolitan area in the $3.00 a gallon plus range."

Arizona's prices should remain 10 to 15 cents below the national averages, which means "you may see summer driving season numbers in the $2.10-$2.35 a gallon range," Kloza said.

U.S. demand for fuel remains poor, with at least 2.5 million barrels per day of extra U.S. refining capability on the shelf, Kloza said. Unemployment has stifled much of the work-related driving, and gasoline imports promise to displace plenty of U.S.-produced fuel from June through December, he said.

"Ultimately, these factors point toward prices not matching the high numbers witnessed in 2005, 2006, 2007 or in the first 10 months of 2008," he said.

The recent jump in gas prices aren't expected to keep many Arizonans from hitting the road this Memorial Day, according to AAA Arizona. An estimated 761,000 Arizonans are projected to travel 50 or more miles from home over the first summer holiday weekend, a 2.5 percent decrease from last year.

"We're still anticipating that a really healthy number of holiday travelers will be doing so by way of motor vehicle, and that's because in most cases auto travel is still the most economical mode of travel," Donati said.

In the Mesa 85201 zip code, for example, the cost of filling a 15-gallon tank now averages $31.62. A year ago, doing so would have cost $54.36.

"That means that for every tank of gas you're filling up right now in that area code, you're paying almost $23 less," Donati said. "Given that prices have come up in the past couple of weeks, since they are still significantly lower than they were this time last year, we're not anticipating that gas prices alone will have an adverse effect on motor vehicle travel."

Motorists won't encounter any construction-related road closures this weekend, said Doug Nintzel, Arizona Department of Transportation spokesman.

"We would expect that State Route 87 as well as Interstate 17 will be busy on Friday afternoon and also on Monday afternoon when folks are returning from trips to the high country," he said. "We recommend that drivers be patient, avoid tailgating and expect the unexpected by bringing some extra drinking water and snacks just in case there's an unscheduled closure."

FREEDOM
COMMUNICATIONS, INC

AAA OPIS Method FAQs Commentary State Prices AAA Maps Links En Español Select A Market

Prices updated as of 6/3/2009 2:59:05 AM

Data provided by Oil Price Information Service *in cooperation with* Wright Express
Media are encouraged to localize fuel price stories by contacting their local AAA club media representative.

Arizona Average Prices

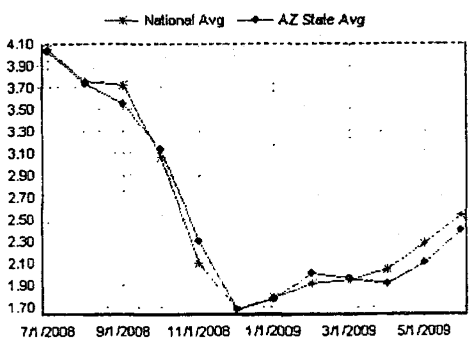
	Regular	Mid	Premium	Diesel
Current Avg.	$2.405	$2.508	$2.653	$2.397
Yesterday Avg.	$2.381	$2.483	$2.626	$2.369
Week Ago Avg.	$2.287	$2.385	$2.523	$2.307
Month Ago Avg.	$1.902	$1.983	$2.097	$2.202
Year Ago Avg.	$3.889	$4.056	$4.289	$4.787

View Arizona Metro Areas

Highest Recorded Average Price:

Regular Unl.	$4.090	7/3/2008
DSL.	$4.855	7/9/2008

12 Month Average For Regular



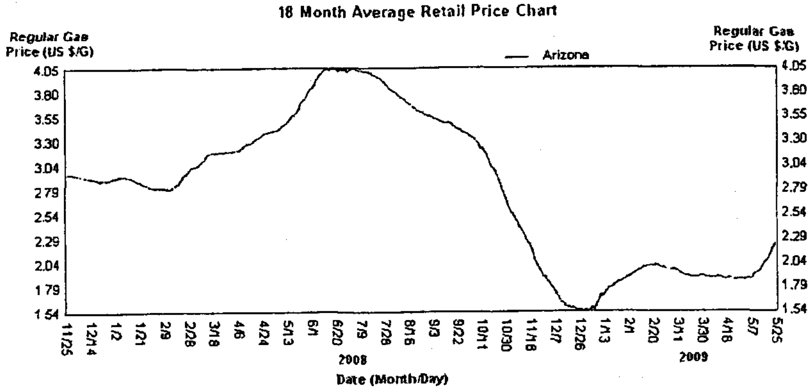
For information on automotive fuel issues, including AAA's recommendations regarding fuel conservation, click here.

AAA's Daily Fuel Gauge Report is updated daily and is the most comprehensive retail gasoline survey available. Every day over 100,000 self-serve stations are surveyed.

Historical Price Charts

Quick charts: 1 Month | 3 Month | 6 Month | 9 Month | 1 Year | 18 month | 2 Years | 3 Years | 4 Years | 5 Years | 6 Years

18 Month Average Retail Price Chart



Add these dynamic charts to your website

Customize Price Charts

Area 1: Arizona, AZ   Time Period: 18 Month   US $/G   Create Chart

Area 2:   Show Crude Oil Price   Canadian c/L

Area 3:

Step One - Select a single city in order to identify price trends or to identify a historical price most accurately. Select multiple cities to compare pump prices between cities.

Step Two - Selection of time duration will define how long into history the prices will be displayed. In some cities only limited price history information is available and in those cases the line will be flat for extended periods.

Step Three - When comparing US cities to Canadian cities you have a choice of price units. The standard unit of measure in the US is dollars per gallon and in Canada the standard is cents/liter. Comparison of US and Canadian cities is done using recent currency exchange rates and uses the conversion factor of 1 US gallon being equal to 3.78 liters. For simple plotting of US cities use dollars per gallon ($/G) and for simple plotting of Canadian cities use cents/liter (c/L).

Step Four - Click the "Create Chart!" button to create the chart

Not Logged In Log In Sign Up Points Leaders

7:44 AM

by GasBuddy.com
ArizonaGasPrices.com

Search for gas prices Advanced
City, State or Zip. Search

Home | Gas Prices | Points & Prizes | Forums | Community | Gas Price Maps | Fuel Saving Tips | Wireless | Media | Help | More

How GasBuddy Works

You spot gas prices

Report your prices

Earn points & win prizes

Help everyone save on gas

Learn More >>

Local Price Snapshot

Today	2.278
Yesterday	2.291
One Week Ago	2.203
One Month Ago	1.876
One Year Ago	3.797

Trend

Prices Falling

[Points Leaders]

Prize Give-Away!

We're giving away a $250 gas card every week!

Next Draw Sunday, May 31, 2009

Learn More Get Tickets

Sponsored by GasBuddy.com

See Prize Winners

Search For Gas Prices

Regular Mid Premium Diesel

Arizona Site Only All of Arizona

Area: All Areas, Ajo, Alpine, Arizona City, Avra Valley

Station: All Stations, 7-Eleven, 76, AAFES, Albertsons

Hold Ctrl to select multiple areas/stations)

Other Area

Prices in the last 48 hours

Search Now! [Top Low & High Prices]

Quick Search for Gas Prices

Find the lowest gas prices in these areas:
Bullhead City Casa Grande Douglas Eloy Flagstaff Florence Kingman Lake Havasu City Nogales Payson Prescott Prescott Valley San Luis Sierra Vista Yuma [More Cities]

Arizona Gas Prices

When you enter a gas price into the above form, you are assisting in the fight against high gasoline prices in Arizona. Together we can work to promote competition and drive down the retail price of gasoline.

Not from Arizona? Try one of these www.GasBuddy.com gas prices sites:

Metro Areas OR States/Provinces Go!

Tell a friend about our site!

Friend's Email Your Name (Advanced) Continue

Unleaded Gasoline Average Prices

	Arizona	USA	Trend
Today	2.278	2.466	
Yesterday	2.291	2.454	

Regular Gas | Midgrade | Premium | Diesel Fuel

Lowest Regular Gas Prices in the Last 48 Hours

Price	Station	Area	Time	Thanks
2.05	Costco 3911 E AZ-69 & Walker Rd	Prescott	Thu 12:30 PM	WingLeader
2.07	ARCO 286 Walker Rd & E AZ-69	Prescott	Thu 12:30 PM	WingLeader
2.07	Sam's Club E AZ-69 & Sundog Ranch Rd	Prescott Valley	Thu 12:30 PM	WingLeader
2.09	Fastrip 1131 AZ-95 & 3rd St	Bullhead City	Thu 9:23 AM	REBELJACK
2.12	Conoco 1981 E Deuce of Clubs near E Adams	Show Low	Fri 2:51 AM	Stoneys
2.15	ARCO 311 Lake Havasu Ave N & Palo Verde Blvd S	Lake Havasu City	Thu 6:41 AM	seadoo27
2.16	Safeway 900 W Deuce of Clubs & S8thAve	Show Low	Fri 2:51 AM	Stoneys
2.17	Maverik 901 N Penrod Rd & US-60	Show Low	Fri 2:51 AM	Stoneys
2.18	ARCO 4670 E US-60 near Ragus Rd	Claypool	Thu 2:47 PM	zeegirl116
2.19	Maverik 2197 McCulloch Blvd & ACOMA Blvd	Lake Havasu City	Fri 7:36 AM	cnet1
2.19	Smith's 80 Acoma Blvd N & Mesquite Ave	Lake Havasu City	Fri 7:36 AM	cnet1
2.19	Maverik 2197 McCulloch Blvd N & Acoma Blvd N	Lake Havasu City	Fri 6:15 AM	seadoo27
2.19	Zip 54 Lake Havasu Ave N & Mesquite Blvd	Lake Havasu City	Fri 6:15 AM	seadoo27
2.19	Gas N Go 1730 N Broad St near N Main St (US 60)	Globe	Thu 2:47 PM	zeegirl116
2.19	Maverick AZ-87 N	Payson	Wed 11:09 PM	screechhawk_1

Add this list of current gas prices to your website

Highest Regular Gas Prices in the Last 48 Hours

Price	Station	Area	Time	Thanks
2.89	Shell 640 S AZ-90 & E Hamilton Ln	Benson	Thu 10:14 AM	Dragnet
2.69	Shell 14905 S Stagecoach Tr near I-17 Exit 262 (Phone 928-632-4521)	Cordes Junction	Thu 12:21 AM	Army2310
2.69	Chevron 19625 E Cordes Lakes Rd & I-17 exit 262 (Phone 928-632-8558)	Cordes Junction	Thu 12:21 AM	Army2310
2.51	Shell B-10 & US-95	Quartzsite	Thu 8:12 PM	spheremaker1

**UNS GAS, INC.'S RESPONSE TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
April 16, 2009**

TF 6.68 As the Company discovers errors in its filing identify such errors and provide documentation to support any changes. Please update this response as additional information becomes available.

RESPONSE: Rate Case Expense Pro Forma Adjustment: this pro forma adjusted test year rate case expense and was composed of an estimate of rate case expense in the current docket and an adjustment related to rate case expense approved in Decision No. 70011 (November 27, 2007). The original adjustment as identified by Bates Nos. UNSG(0571)02687 to UNSG(0571)02688 and the associated Excel file not identified by Bates numbers (both provided in response to Staff Data Request JMK-1.1) requires a correction for an additional adjustment to test year expense that was overlooked. The additional adjustment is to remove test year amortization of rate case expense for $200,000 of the $300,000 allowed in Decision No. 70011 for the 2006 rate case that will be recovered prior to new rates becoming effective, resulting in a reduction of test year expense of $58,333.

Please see the Excel workbook TF 6.68 (Income - Rate Case Expense 6-30-08 Corrected) on the enclosed CD.

The Excel file on the CD is not identified by Bates numbers.

RESPONDENT: Janet Zaidenberg-Schrum

WITNESS: Dallas Dukes

UNS GAS, INC.
RATE BASE PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2008

CORRECTED PRO FORMA ADJUSTMENT FOR STAFF DATA REQUEST TF 6.68

ADJUSTMENT NAME:	Rate Case Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	April 8, 2009
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
928	Regulatory Expense (A)	$33,333	
928	Regulatory Expense (B)	$166,667	
407	**Amortization of Regulatory Assets - Rate Case Expense**		**$58,333**
	ENTRY TOTAL	**$200,000**	**$58,333**
	NET ENTRY	**$141,667**	

Reason for Adjustment

A) To include rate case expense approved in ACC Decision No. 70011 for the 2006 rate case.

B) To include an estimate of outside expenditures for the rate case expense amortization for $500,000 total expense amortized over 3 years @ $166,667 per year.

Addition to Original Pro Forma to correct test year expense

C) To remove test year amortization of rate case expense for $200,000 of the $300,000 allowed in ACC Decision No. 70011 for the 2006 rate case that will be recovered prior to new rates becoming effective.

Note: Pro forma adjustments related to the write-off 2006 rate case expense not included in the $300,000 allowed in ACC Decision No. 70011 are included in the pro forma adjustment for Miscellaneous Expenses.

UNS Gas, Inc.
Rate Case Expense Per ACC Decision No. 70011
Test Year Ended June 30, 2008

Rate Case Expense allowed per ACC Decision No. 70011		$300,000
Yearly Amortization (starting December 2007)		$100,000
Monthly Amortization (starting December 2007)		$8,333
Amortization December 2007 - November 2009 (24 months)	\1	$200,000
Remaining Balance @ November 30, 2009		$100,000
Amortization for Test Year Balance @ November 30, 2009 over 3 years		$33,333

\1 Assumption: new rates will go into effect 14 months after the rate case is filed in October 2008 (in effect as of December 1, 2009).

Correction of original pro forma	
Assumptions for recovery of $300k	
Rates in effect 12/1/07 through 11/30/09 = 24 months	
24 months of rate case expense recovery =	$200,000
Monthly rate case expense recovery over 24 months	$8,333
Rate case expense in test year - to be removed	**$58,333**
Remaining expense to be recovered over 3 more years	$100,000
New rates in effect 12/1/09 - 11/30/12 = 36 months	
Yearly rate case expense recovery of $100k over3 years	$33,333
Monthly rate case expense recovery of $100k over 36 months	$2,778

**UNS GAS, INC.'S RESPONSE TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
May 7, 2009**

RUCO 1.90 Refer to K. Kissenger's testimony, page 8.

a. What is the 2008 statutory assessment ratio?

b. Provide the most current known average property tax rates used. Identify and provide a copy of the source

RESPONSE:

a. The 2008 statutory assessment ratio is 23%.

b. The most current average known property tax rate is for the 2008 tax year. That rate is 7.6127%. The calculation of the rate is shown in the PDF file RUCO 1.90, Bates Nos. UNSG(0571)09064, on the enclosed CD. The source of the individual rates for each tax district is the property tax bills sent by the counties. There are hundreds of these bills so they have not been included in the supporting attachments. A review of the bills for the 2008 tax year can be arranged at a mutually agreed upon time and place, if necessary.

RESPONDENT: Gail Boswell

WITNESS: Karen Kissinger

UNS Gas, Inc.

Tax Year *2008*

Average Property Tax Rate

County	*Full Cash Value*	*Taxable Value*	*Property Tax*	*Avg Tax Rate*
Coconino	25,213,370	5,799,075	434,457	7.4918%
Mohave	18,447,130	4,242,840	292,896	6.9033%
Navajo	20,920,491	4,811,713	384,561	7.9922%
Santa Cruz	7,296,504	1,678,196	179,004	10.6664%
Yavapai	57,176,173	13,150,520	968,709	7.3663%
Total	*129,053,668*	*29,682,344*	*2,259,626*	*7.6127%*

UNS Gas, Inc.
Pro Forma ADIT - Summary
Test Year Ended 6/30/2008
\\Cds_1\corpdata\TAXSVCS\Rate Cases\UNSG\2008 06-30 TY\ADIT\[UNSG ADIT TY 06-30-08.xls]A1 - Summary

		ADIT Per Financial Statements		Pro Forma ADIT	Change in ADIT
Account 190					
Bad Debt	G1.1-G1.2	463,156		-	(463,156)
CIAC	G1.1-G1.2	2,724,268	E1.1a	2,436,909	(287,359)
Customer Advances	G1.1-G1.2	4,970,984	F1.1a	4,402,955	(568,029)
Customer Advances - CWIP	G1.1-G1.2	-	I1A	(227,413)	(227,413)
Dividend Equivalents	G1.1-G1.2	18,417	*	17,952	(465)
DSM Adjustor	G1.1-G1.2	55,568			(55,568)
FAS 106	G1.1-G1.2	1,054			(1,054)
FAS 112	G1.1-G1.2	30,983		-	(30,983)
Incentive Comp PEP	G1.1-G1.2	(818)		-	818
Other Comprehensive Income FAS 106	G1.1-G1.2	(19,820)		-	19,820
Restricted Stock	G1.1-G1.2	24,946	*	24,316	(630)
Restricted Stock - Directors	G1.1-G1.2	56,713	*	55,281	(1,432)
Stock Options	G1.1-G1.2	159,742	*	155,708	(4,034)
Vacation	G1.1-G1.2	173,755	*	169,367	(4,388)
Total Account 190		8,658,948		7,035,076	(1,623,872)
Account 282					
Net Plant ADIT	G1.1-G1.2	(20,473,284)	B1.1a+B2.1a	(17,452,856)	3,020,428
~~Net CWIP ADIT~~	G1.1-G1.2	(162,379)	C7.3i	-	162,379
Total Account 282		(20,635,663)		(17,452,856)	3,182,807
Account 283					
CARES Reg Asset	G1.1-G1.2	(195,073)	H1.1A	(190,140)	4,933
OCI-Cash Flow Hedge Gas Cur		(1,559,519)			1,559,519
OCI-Cash Flow Hedge Gas NC		(1,367,888)			1,367,888
Pension	G1.1-G1.2	1,072	*	1,045	(27)
Rate Case Expenses	G1.1-G1.2	(153,949)		-	153,949
SERP	G1.1-G1.2	195,089		-	(195,089)
Total Account 283		(3,080,268)		(189,095)	2,891,173
Grand Total		(15,056,983)		(10,606,875)	4,450,108

*Adjsuted from 39.6% tax rate used for income tax accounting to 38.6% tax rate used for ratemaking.

ACCOUNTING DEPARTMENT
Prepared by MBell 10-8-2008
Checked by [illegible] 10/10/08
Approved by
Input by
Other side of I/C in J#____ by ____

UNS Gas, Inc.
Test Year Ended June 30, 2008
Depreciation & Amortization Expense by Plant FERC account

From Revenue Requirement Model (data from Plant Accounting)

					C	D				E	A
Function	Plt Acct & Desc	0403	0404	Total 403 & 404	% 403 of Total	% 404 of Total	0406	Total	Citizens Acq Discount 0406	Citizens Acq % 406 of Total	So Union Acq Premium 0406
Intangible	302-Franchise	0.00	15,574.49	15,574.49	0.00%	1.26%	(2,398.42)	13,176.07	(3,224.55)	0.1827%	826.13
Intangible	303-Intangibles	0.00	1,218,556.40	1,218,556.40	0.00%	98.74%	4,042.39	1,222,598.79	(4,423.65)	0.2507%	8,466.04
		0.00	1,234,130.89	1,234,130.89			1,643.97	1,235,774.86	(7,648.20)		9,292.17
Transmission	365-Land & Land Rights	826.00	0.00	826.00	0.01%	0.00%	(276.57)	549.43	(276.57)	0.0157%	0.00
Transmission	366-Struct & Imprv	662.89	0.00	662.89	0.01%	0.00%	(206.04)	456.85	(206.04)	0.0117%	0.00
Transmission	367-Mains	343,544.57	0.00	343,544.57	4.12%	0.00%	(55,515.44)	288,029.13	(55,515.44)	3.1456%	0.00
Transmission	369-Meas & Reg St Eq	56,068.22	0.00	56,068.22	0.67%	0.00%	(14,831.21)	41,237.01	(14,831.21)	0.8404%	0.00
Transmission	371-Other Eq	6,491.11	0.00	6,491.11			(1,904.59)	4,586.52	(1,904.59)	0.1079%	0.00
		407,592.79	0.00	407,592.79			(72,733.85)	334,858.94	(72,733.85)		0.00
Distribution	374-Land & Land Rights	1,213.73	0.00	1,213.73	0.01%	0.00%	(406.35)	807.38	(406.35)	0.0230%	0.00
Distribution	375-Struct & Imprv	203.85	0.00	203.85	0.00%	0.00%	(13.93)	189.92	(13.93)	0.0008%	0.00
Distribution	376-Mains	3,527,325.90	0.00	3,527,325.90	42.26%	0.00%	(570,388.01)	2,956,937.89	(822,542.94)	46.6072%	252,154.93
Distribution	378-Meas & Reg St Eq	72,346.23	0.00	72,346.23	0.87%	0.00%	(6,460.40)	65,885.83	(12,595.73)	0.7137%	6,135.33
Distribution	379-Meas & Reg St Eq (City)	69,689.58	0.00	69,689.58	0.83%	0.00%	(6,325.33)	63,364.25	(12,656.07)	0.7171%	6,330.74
Distribution	380-Services	2,442,227.93	0.00	2,442,227.93	29.26%	0.00%	(317,309.45)	2,124,918.48	(421,361.85)	23.8754%	104,052.40
Distribution	381-Meters	274,799.83	0.00	274,799.83	3.29%	0.00%	(35,276.43)	239,523.40	(52,550.95)	2.9777%	17,274.52
Distribution	382-Meter Install	203,625.88	0.00	203,625.88	2.44%	0.00%	(39,449.54)	164,176.34	(39,595.85)	2.2436%	146.31
Distribution	383-House Reg	74,055.60	0.00	74,055.60	0.89%	0.00%	(13,183.45)	60,872.15	(10,307.79)	0.5841%	(2,875.66)
Distribution	384-House Reg Install	38,170.86	0.00	38,170.86	0.46%	0.00%	(5,152.66)	33,018.20	(5,152.66)	0.2920%	0.00
Distribution	385-Indust Meas & Reg St Eq	22,288.80	0.00	22,288.80	0.27%	0.00%	939.91	23,228.71	(6,311.64)	0.3576%	7,251.55
Distribution	387-Other Eq	(13,425.15)	0.00	(13,425.15)	-0.16%	0.00%	(3,749.90)	(17,175.05)	(9,967.66)	0.5648%	6,217.76
		6,712,523.04	0.00	6,712,523.04			(996,775.54)	5,715,747.50	(1,393,463.42)		396,687.88
General	389-Land & Land Rights	923.44	0.00	923.44	0.01%	0.00%	761.46	1,684.90	(2,791.40)	0.1582%	3,552.86
General	390-Struct & Imprv	231,073.72	0.00	231,073.72	2.77%	0.00%	(4,443.67)	226,630.05	(12,094.87)	0.6853%	7,651.20
General	391-Furn & Eq	672,571.67	0.00	672,571.67	8.06%	0.00%	(210,366.77)	462,204.90	(211,304.61)	11.9730%	937.84
General	392-Transp Eq	(19,662.42)	0.00	(19,662.42)	-0.24%	0.00%	0.00	(19,662.42)	0.00	0.0000%	0.00
General	393-Stores Eq	5,450.95	0.00	5,450.95	0.07%	0.00%	(393.79)	5,057.16	(1,159.99)	0.0657%	766.20
General	394-Tools, Shp & Gar	86,577.50	0.00	86,577.50	1.04%	0.00%	(3,119.67)	83,457.83	(19,782.04)	1.1209%	16,662.37
General	395-Lab Eq	75,252.83	0.00	75,252.83	0.90%	0.00%	(18,232.75)	57,020.08	(18,232.75)	1.0331%	0.00
General	396-Power Op Eq	100,257.71	0.00	100,257.71	1.20%	0.00%	(2,106.11)	98,151.60	(979.19)	0.0555%	(1,126.92)
General	397-Comm Eq	69,771.46	0.00	69,771.46	0.84%	0.00%	(22,008.84)	47,762.62	(22,008.84)	1.2471%	0.00
General	398-Misc Eq	11,248.18	0.00	11,248.18	0.13%	0.00%	(2,669.73)	8,578.45	(2,640.57)	0.1496%	(29.16)
		1,233,465.04	0.00	1,233,465.04			(262,579.87)	970,885.17	(290,994.26)		28,414.39
	Total	8,353,580.87	1,234,130.89	9,587,711.76	100.00%	100.00%	(1,330,445.29)	8,257,266.47	E (1,764,839.73)	100.00%	434,394.44 B
Excluding FERC 371 (Griffith Plant)		8,347,089.76	1,234,130.89								
Y2K Amortization (FERC 407)				76,752.96				76,752.96			
CARES Asset Amortization (FERC 407)				56,932.52				56,932.52			
Rate Case Expense Amortization (FERC 407)				58,333.31				58,333.31			
Prescott Building Gain Amortization (FERC 407)				(11,815.30)				(11,815.30)			
	Total FERC 407			180,203.49				180,203.49			
	Total Depreciation & Amortization Expense			9,767,915.25				8,437,469.96	Ties to income statement		

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UNS GAS, INC.

INCOME STATEMENT PRO FORMA ADJUSTMENT

TEST YEAR ENDED SEPTEMBER 30, 2007

ADJUSTMENT NAME:	Depr & Amort Annualization - Detail by FERC Account
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 21, 2008
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
A. FERC 403 & 404			
302	Franchises and Consents		$50
303	Miscellaneous Intangible Plant		$3,883
365	Land & Land Rights		$72
366	Structures & Improvements		$58
367	Mains		$30,068
369	Measuring and Reg. Station Equipment		$4,907
371	Other Equipment (Griffith)		$6,491
374	Land, Land Rights, Easements		$106
375	Structures & Improvements		$18
376	Mains		$308,724
378	Meas. and Reg. Station Equipment - General		$6,332
379	Meas. and Reg. Station Equipment - City Gate Check Station		$6,099
380	Services		$213,752
381	Meters		$24,051
382	Meter Installations		$17,822
383	House Regulators		$6,482
384	House Regulatory Installations		$3,341
385	Industrial Meas. & Reg. Station Equipment		$1,951
387	Other Equipment	$1,175	
389	Land & Land Rights		$81
390	Structures & Improvements		$20,224
391	Office Furniture and Equipment		$58,866
392	Transportation Equipment	$1,721	
393	Stores Equipment		$477
394	Tools, Shop and Garage Equipment		$7,578
395	Laboratory Equipment		$6,586
396	Power Operated Equipment		$8,775
397	Communication Equipment		$6,107
398	Miscellaneous Equipment		$984
	Total Annualization - FERC 403 & 404	**$2,896**	**$743,885**
	Net Adjustment - Annualization		**$740,989**

UNS GAS, INC.

INCOME STATEMENT PRO FORMA ADJUSTMENT

TEST YEAR ENDED SEPTEMBER 30, 2007

ADJUSTMENT NAME:	Depr & Amort Annualization - Detail by FERC Account
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 21, 2008
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
A. FERC 406 - Citizens Acquisition Discount			
302	Franchises and Consents	$1,731	
303	Miscellaneous Intangible Plant	$2,375	
365	Land & Land Rights	$148	
366	Structures & Improvements	$111	
367	Mains	$29,802	
369	Measuring and Reg. Station Equipment	$7,962	
371	Other Equipment	$1,022	
374	Land, Land Rights, Easements	$218	
375	Structures & Improvements	$7	
376	Mains	$441,561	
378	Meas. and Reg. Station Equipment - General	$6,762	
379	Meas. and Reg. Station Equipment - City Gate Check Station	$6,794	
380	Services	$226,197	
381	Meters	$28,211	
382	Meter Installations	$21,256	
383	House Regulators	$5,533	
384	House Regulatory Installations	$2,766	
385	Industrial Meas. & Reg. Station Equipment	$3,388	
387	Other Equipment	$5,351	
389	Land & Land Rights	$1,498	
390	Structures & Improvements	$6,493	
391	Office Furniture and Equipment	$113,433	
393	Stores Equipment	$623	
394	Tools, Shop and Garage Equipment	$10,619	
395	Laboratory Equipment	$9,788	
396	Power Operated Equipment	$526	
397	Communication Equipment	$11,815	
398	Miscellaneous Equipment	$1,418	
	Total Annualization - Citizens Discount FERC 406	**$947,408**	**$0**
	Net Adjustment - Annualization	**$947,408**	

UNS GAS, INC.

INCOME STATEMENT PRO FORMA ADJUSTMENT

TEST YEAR ENDED SEPTEMBER 30, 2007

ADJUSTMENT NAME:	Depr & Amort Annualization - Detail by FERC Account
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 21, 2008
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
B. FERC 406 - Southern Union Acquisition Premium			
302	Franchises and Consents		$826
303	Miscellaneous Intangible Plant		$8,466
376	Mains		$252,155
378	Meas. and Reg. Station Equipment - General		$6,135
379	Meas. and Reg. Station Equipment - City Gate Check Station		$6,331
380	Services		$104,052
381	Meters		$17,275
382	Meter Installations		$146
383	House Regulators	$2,876	
385	Industrial Meas. & Reg. Station Equipment		$7,252
387	Other Equipment		$6,218
389	389-Land & Land Rights		$3,553
390	Structures & Improvements		$7,651
391	Office Furniture and Equipment		$938
393	Stores Equipment		$766
394	Tools, Shop and Garage Equipment		$16,662
396	Power Operated Equipment	$1,127	
398	Miscellaneous Equipment	$29	
	Total Southern Union	**$4,032**	**$438,426**
	Net Adjustment - Southern Union FERC 406		**$434,394**
	ENTRY TOTAL	**$954,335**	**$1,182,311**
	NET ENTRY		**$227,976**

Reason for Adjustment

A. To adjust test year recorded depreciation and amortization expense to reflect the final adjusted balances of Plant in Service and the Acquisition Discount/Premium and the depreciation rates produced by Dr. White's study.

B. To remove the Southern Union Acquisition Premium amortization expense - premium is excluded from rate base.

UNS GAS, INC.

INCOME STATEMENT PRO FORMA ADJUSTMENT

TEST YEAR ENDED JUNE 30, 2008

ADJUSTMENT NAME:	Depreciation Annualization
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 9, 2008
PREPARED BY:	E. Fowler
CHECKED BY:	D. Grant
REVIEWED BY:	C. Dabelstein

Revised to break out Acquisition Adjustment pro forma into Citizens & Southern Union

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
403	Depreciation Expense		$737,057
404	Amortization of Utility Plant		$3,933
	Net Depreciation & Amortization Adjustment		$740,990
406	Amortization of Utility Plant Acquisition Adjustments - Citizens	$947,408	
406	Amortization of Utility Plant Acquisition Adjustments - So. Union		$434,394
	Net Amortization Adjustment - Acquisition Adj.	$513,013	
	ENTRY TOTAL	**$947,408**	**$1,175,384**
	NET ENTRY		**$227,976**

Reason for Adjustment

To adjust test year recorded depreciation and amortization expense to reflect the final adjusted balances of Plant in Service and the Acquisition Discount/Premium and the depreciation rates produced by Dr. White's

UNS Gas, Inc.
Depreciation Annualization Adjustment

	A	B	C = A+B	D	E	F = D+E	Calc = C * D	Calc = C * E	Calc = C * F					
Description	Balance at 6/30/08	Rate Case Adjustments	Adjusted Balance	Investment Rate	Cost of Removal	Depreciation Rate %	Investment Rate Component	Cost of Removal Component	Annualized Depreciation	FERC 403 %	Alloc of Adj to FERC 403	FERC 404 %	Alloc of Adj to FERC 404	Total FERC 403 & 404
Intangible Plant:														
Acct. 302 Franchises and Consents	362,992	-	362,992	4.00%		4.00%	14,520	-	14,520	0.00%	-	1.26%	(50)	(50)
Acct. 303 Misc. Intangible Plant	777,500	-	777,500	6.67%		6.67%	51,859	-	51,859	0.00%	-	98.74%	(3,883)	(3,883)
Total	1,140,492	-	1,140,492				66,379	-	66,379					
Transmission Plant:														
Acct. 365 Land Rights of Way	102,606	(16,533)	86,073	1.38%		1.38%	1,188	-	1,188	0.01%	(72)	0.00%	-	(72)
Acct. 366 Structures & Improvements	16,853	(1,061)	15,792	1.55%		1.55%	245	-	245	0.01%	(58)	0.00%	-	(58)
Acct. 367 Mains	22,312,011	(4,825,131)	17,486,880	1.40%	0.13%	1.53%	244,816	22,733	267,549	4.12%	(30,068)	0.00%	-	(30,068)
Acct. 369 Measuring and Regulating Station Equipment	3,574,097	(2,782,032)	792,065	1.46%	0.08%	1.54%	11,564	634	12,198	0.67%	(4,907)	0.00%	-	(4,907)
Acct. 371 Other Equipment (Griffith Plant)	183,581	(183,581)	-	2.49%		2.49%	-	-	-		(6,491)			(6,491)
Total	26,189,148	(7,808,338)	18,380,810				257,813	23,367	281,180					
Distribution Plant:														
Acct. 374 Land	127,927	(8,051)	119,876	0.00%		0.00%	-	-	-					
Acct. 374 Land Rights of Way	25,111	(1,580)	23,531	0.93%		0.93%	219	-	219					
Acct. 374 Easements	104,951	(6,604)	98,347	1.76%		1.76%	1,731	-	1,731	0.01%	(106)	0.00%	-	(106)
Acct. 375 Structures & Improvements	10,948	(689)	10,259	1.93%		1.93%	198	-	198	0.00%	(18)	0.00%	-	(18)
Acct. 376 Mains	170,344,633	(13,217,236)	157,127,397	1.72%	0.35%	2.07%	2,702,591	549,946	3,252,537	42.26%	(308,724)	0.00%	-	(308,724)
Acct. 378 Measuring and Regulating Station Equipment - General	2,501,503	(157,421)	2,344,082	2.29%	0.68%	2.97%	53,679	15,939	69,618	0.87%	(6,332)	0.00%	-	(6,332)
Acct. 379 Measuring and Regulating Station Equipment - City Gate	3,789,758	(1,352,687)	2,437,071	2.36%		2.36%	57,515	-	57,515	0.83%	(6,099)	0.00%	-	(6,099)
Acct. 380 Services	86,176,958	271,433	86,448,391	1.39%	1.43%	2.82%	1,201,633	1,236,212	2,437,845	29.26%	(213,752)	0.00%	-	(213,752)
Acct. 381 Meters	13,780,226	-	13,780,226	2.02%		2.02%	278,361	-	278,361	3.29%	(24,051)	0.00%	-	(24,051)
Acct. 382 Meter Installations	8,633,492	-	8,633,492	2.36%		2.36%	203,750	-	203,750	2.44%	(17,822)	0.00%	-	(17,822)
Acct. 383 House Regulators	2,886,748	-	2,886,748	2.56%		2.56%	73,901	-	73,901	0.89%	(6,482)	0.00%	-	(6,482)
Acct. 384 House Regulator Installations	1,352,659	-	1,352,659	2.80%		2.80%	37,874	-	37,874	0.46%	(3,341)	0.00%	-	(3,341)
Acct. 385 Industrial Measuring and Regulating Station Equipment	1,445,920	(12,609)	1,433,311	1.83%	0.87%	2.70%	26,229	12,470	38,699	0.27%	(1,951)	0.00%	-	(1,951)
Acct. 387 Other Work Equipment	1,141,520	(71,836)	1,069,684	3.01%		3.01%	32,197	-	32,197	-0.16%	1,175	0.00%	-	1,175
Total	292,322,354	(14,557,280)	277,765,074				4,669,878	1,814,567	6,484,445					

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Description	Balance at 6/30/08 (A)	Rate Case Adjustments (B)	Adjusted Balance (C = A+B)	Investment Rate (D)	Cost of Removal (E)	Depreciation Rate % (F = D+E)	Investment Rate Component (Calc = C * D)	Cost of Removal Component (Calc = C * E)	Annualized Depreciation (Calc = C * F)	FERC 403 %	Alloc of Adj to FERC 403	FERC 404 %	Alloc of Adj to FERC 404	Total FERC 403 & 404
General Plant:														
Acct. 389 Land	362,012	-	362,012	0.00%		0.00%	-	-	-					
Acct. 389 Land Rights	32,109	-	32,109	4.93%		4.93%	1,583	-	1,583	0.01%	(81)	0.00%	-	(81)
Acct. 390 Structures & Improvements	5,305,943	39,408	5,345,351	4.89%		4.89%	261,388	-	261,388	2.77%	(20,224)	0.00%	-	(20,224)
Acct. 391 Office Furniture & Equipment	1,443,680	12,493	1,456,173	4.55%		4.55%	66,256	-	66,256					
Acct. 391 Computer Equipment - PCs	641,158	5,548	646,706	20.00%		20.00%	129,341	-	129,341	8.06%	(58,866)	0.00%	-	(58,866)
Acct. 392 Transportation Equipment - Class 1	819,556	10,744	830,300	14.71%		14.71%	122,137	-	122,137					
Acct. 392 Transportation Equipment - Class 2	2,611,235	34,232	2,645,467	17.87%		17.87%	472,745	-	472,745					
Acct. 392 Transportation Equipment - Class 3	1,340,149	17,568	1,357,717	22.68%		22.68%	307,930	-	307,930					
Acct. 392 Transportation Equipment - Class 4	1,190,586	15,608	1,206,194	13.04%		13.04%	157,288	-	157,288					
Acct. 392 Transportation Equipment - Class 5	1,126,671	14,770	1,141,441	11.84%	-0.01%	11.83%	135,146	(114)	135,032	-0.24%	1,721	0.00%	-	1,721
Acct. 393 Stores Equipment	200,996	-	200,996	2.86%		2.86%	5,748	-	5,748	0.07%	(477)	0.00%	-	(477)
Acct. 394 Tools, Shop, & Garage Equip.	2,262,055	9,431	2,271,486	4.00%		4.00%	90,859	-	90,859	1.04%	(7,578)	0.00%	-	(7,578)
Acct. 395 Laboratory Equipment	600,654	186,174	786,828	11.11%		11.11%	87,417	-	87,417	0.90%	(6,586)	0.00%	-	(6,586)
Acct. 396 Power Operated Equip.	1,209,317	69,759	1,279,076	10.13%	0.36%	10.49%	129,570	4,605	134,175	1.20%	(8,775)	0.00%	-	(8,775)
Acct. 397 Communications Equip.	1,078,532	23,293	1,101,825	6.67%		6.67%	73,492	-	73,492	0.84%	(6,107)	0.00%	-	(6,107)
Acct. 398 Misc. Equipment	277,567	-	277,567	4.00%		4.00%	11,103	-	11,103	0.13%	(984)	0.00%	-	(984)
Total	20,502,220	439,028	20,941,248				2,052,003	4,491	2,056,494					-
										100.00%	(737,057)	100.00%	(3,933)	(740,990)

Pro Forma Acct. 392 Depreciation X 26.6%	Total Annualized Depreciation	8,888,498
	Less: Vehicle Depreciation Charged to CWIP	(317,905)
	Total Annualized Depreciation Expense	8,570,593
Test Year Acct. 392 depreciation X 73.4%	Test Year Recorded Depreciation Expense	9,577,868
	Add: Vehicle Depreciation cleared to O&M	1,049,065
	Less: System Allocations (GL Account 56000)	(1,315,350)
	Test Year Depreciation Expense	9,311,583
	Adjustment Required	(740,990)

Allocated Call Center and other depreciation charged to UNSG depreciation expense not applicable to UNSG plant assets.

	Acct. 403	Acct. 404	O&M Exp.	Total
Test Year Recorded	8,192,206	70,312	1,049,065	9,311,583
T.Y. As Adjusted - Annualized	8,822,119	66,379		8,888,498
Vehicle Depreciation Chgs CWIP	(1,195,132)		877,227	(317,905)
	7,626,987	66,379	877,227	8,570,593
Adjustment amount	(565,219)	(3,933)	(171,838)	(740,990)

	Total Pro Forma	Less: Griffith	Adjusted Pro Forma To Allocate
Total FERC 403	(737,057)	(6,491)	(730,566)
Total FERC 404	(3,933)	-	(3,933)
Total	(740,990)	(6,491)	(734,499)

Griffith plant is removed 100%; this removes 100% of Griffith depreciation by itself and leaves the remaining pro forma adjustment amount to be allocated to the other FERC accounts. The total pro forma is the same - only presentation changed so that Griffith was separated.

	A	B	C = A+B	D	E	F = D+E	Calc = C * D	Calc = C * E	Calc = C * F					
Description	Balance at 6/30/08	Rate Case Adjustments	Adjusted Balance	Investment Rate	Cost of Removal	Depreciation Rate %	Investment Rate Component	Cost of Removal Component	Annualized Depreciation	FERC 403 %	Alloc of Adj to FERC 403	FERC 404 %	Alloc of Adj to FERC 404	Total FERC 403 & 404

Note--for purposes of the adjustment, vehicle depreciation in O&M is treated as being in Acct. 403

**UNS GAS, INC.'S RESPONSE TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
April 16, 2009**

TF 6.54 Please list all membership payments made to industry associations (e.g., American Gas Association, Institute of Gas Technology, etc.) requested for recovery during the test year. Identify the account into which such amounts are charged.

a. State the purpose and objective of each organization listed.

b. Provide descriptive material the Company has concerning each organization's financial statements, annual budget, and activities.

c. Do any of the organizations listed engage in lobbying or advocacy activities, attempts to influence public opinion, institutional or image-building advertising? If so, list each organization which engages in such activities, and state the Company's best estimate of the portion of the organization's expenses devoted to such activities. Explain and show how such estimates were derived. State if the Company has included the portions of dues related to such activities in the test year.

RESPONSE: UNS Gas has memberships with the American Gas Association ("AGA") only.

a., b. Please see the PDF files TF 6.54 (AGA Dues) and TF 6.54 (AGA Return), Bates Nos. UNSG(0571)07347 to UNSG(0571)07356 on the enclosed CD, as responses to parts "a" and "b."

The calculation for the AGA Dues was derived by taking the 2007 & 2008 invoices dividing them by 2, getting the last half of 2007 and the first half of 2008 for the test year. This amount was reduced by the percentage of AGA dues used for marketing.

c. The AGA engages in lobbying and UNS Gas has removed the portion of its membership dues that would cover that expense by the AGA.

RESPONDENT: Gary A. Smith

WITNESS: Gary A. Smith

AMERICAN GAS ASSOCIATION
2007 BUDGET

	\$ 2007 ALLOCATION	% 2007 ALLOCATION
Advertising	\$345,000	1.39%
Corporate Affairs	\$2,099,000	8.44%
General & Administrative	\$4,665,000	18.77%
General Counsel	\$1,016,000	4.09%
Industry Finance & Administrative Programs	\$1,283,000	5.16%
Operations & Engineering Management	\$5,993,000	24.11%
Policy, Planning & Regulatory Affairs	\$3,669,000	14.76%
Public Affairs	\$5,790,000	23.29%
Total Budget	\$24,860,000	100.00%

Note:
Lobbying expenses, as defined under IRC Section 162, accounted for 2.12% of member dues in 2007.

AMERICAN GAS ASSOCIATION
2008 BUDGET

	\$ 2008 ALLOCATION	% 2008 ALLOCATION
Advertising	\$300,000	1.18%
Corporate Affairs	\$2,317,000	9.14%
General & Administrative	\$5,127,000	20.22%
General Counsel	\$1,056,000	4.17%
Industry Finance & Administrative Programs	\$852,000	3.36%
Operations & Engineering Management	\$5,505,000	21.71%
Policy, Planning & Regulatory Affairs	\$4,000,000	15.78%
Public Affairs	\$6,195,000	24.44%
Total Budget	\$25,352,000	100.00%

Note
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 4% of member dues in 2008.

AGA Vision and Mission Statement

VISION STATEMENT

AGA's vision is to be the most effective and influential energy trade association in the United States while providing clear value to its membership.

MISSION STATEMENT

The American Gas Association represents companies delivering natural gas to customers to help meet their energy needs. AGA members are committed to delivering natural gas safely, reliably and cost-effectively in an environmentally responsible way. AGA advocates the interests of its members and their customers, and provides information and services promoting efficient demand and supply growth and operational excellence in the safe, reliable and efficient delivery of natural gas.

To further this mission, AGA:

1. Encourages, facilitates, and assists members in sharing information designed to achieve operational excellence by improving their safety, security, reliability, efficiency, and environmental and other performance metrics;

2. Assists members in managing and responding to customer energy needs, regulatory trends, natural gas markets, capital markets and emerging technologies;

3. Collects, analyzes and disseminates data on a timely basis to policy makers and the public about energy utilities and the natural gas industry;

4. Focuses on the advocacy of natural gas issues that are priorities for the membership and that are achievable in a cost-effective way;

5. Serves as a voice on behalf of the energy utility industry and promotes natural gas demand growth by emphasizing before a variety of audiences the energy efficiency, environmental and other benefits of natural gas and promotes natural gas supply growth by advocating public policies favorable to increased supplies and lower prices to customers; and

6. Delivers measurable value to AGA members.

Approved September 19, 2006

AGA Committee Structure

(Shaded Committees are Board level)

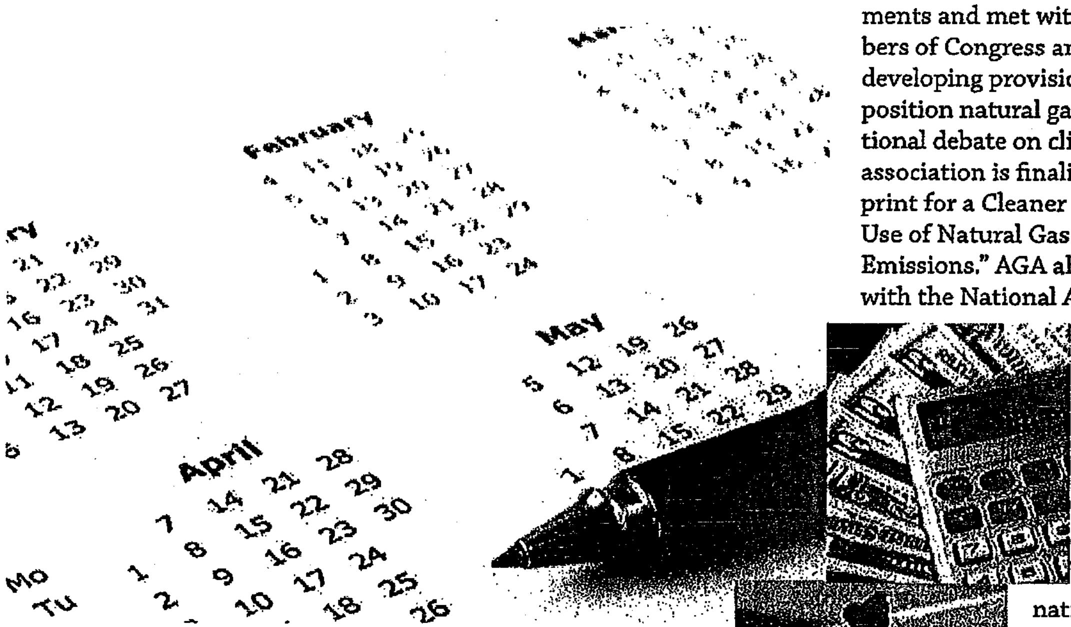
- **AGA Board of Directors/ Executive Committee**
  Chairman, *David M. McClanahan*
  1st Vice Chairman, *Thomas E. Skains*
  2nd Vice Chairman, *Robert C. Skaggs, Jr.*
  - **Nominating Committee**
    Chairman, *Thomas E. Skains*
  - **Board Audit Committee**
    Chairman, *Glenn R. Jennings*
  - **Board Finance Committee**
    Chairman, *James H. DeGraffenreidt, Jr.*
  - **Compensation Committee**
    Chairman, *David M. McClanahan*
  - **Strategic Planning Committee**
    Chairman, *Thomas E. Skains*
  - **Government Relations Policy Committee**
    Chairman, *Kevin Burke*
    - **Legislative Committee**
      Chairman, *Junior Aston*
    - **FERC Regulatory Committee**
      Chairman, *Bridget E. Shahan*
    - **State Regulatory Committee**
      Chairman, *Charles J. Harder*
    - **Public Relations Committee**
      Chairman, *Chad K. Jones*
    - ***Operations Safety Regulatory Action Committee**
      Chairman, *Paul M. Preketes*
    - ***Environmental Regulatory Action Committee**
      Chairman, *Daniel E. Smith, III*
  - **Safety Committee**
    Chairman, *Kenneth W. DeFontes, Jr.*
  - **Security, Integrity & Reliability Committee**
    Chairman, *Alan K. Allred*
  - **Membership Services Committee**
    Chairman, *John Russell*
  - **Small Member Council**
    Chairman, *John B. Williamson, III*
  - **Legal Committee**
    Chairman, *Paul R. Shlanta*
  - **Leadership Council**
    Chairman, *Robert C. Skaggs, Jr.*
  - **Climate Change Task Force**, Chairman, *Mark S. Dodson*
  - **Operating Section Managing Committee**
    Chairman, *Susan L. Fleck*
    - Building Energy Codes & Stds.
    - Corrosion Control
    - Distribution Construction & Maintenance
    - Distribution & Transmission Engineering
    - Distribution Measurement
    - Environmental Matters
    - Executive Committee
    - Gas Control
    - Natural Gas Security
    - Plastic Materials
    - Safety & Occupational Health
    - Supplemental Gas
    - Transmission Measurement
    - Underground Storage
    - Utility & Customer Field Services
  - **Marketing Communications Committee**
    Chairman, *Donna N. Peeples*
  - **Finance Committee**
    Chairman, *David H. Anderson*
    - Accounting Advisory Council
    - Accounting Principles
    - Accounting Services
    - Compensation & Benefits
    - Customer Service
    - Human Resources Policy
    - Internal Audit
    - Labor Relations
    - Rate
    - Risk Management
    - Taxation
    - Technology Advisory Council
  - **Operations & Engineering Services Associates Section Managing Committee**
    Chairman, *Scott A. Kranstuber*

*Regulatory Action committees also report to the Operating Section Managing Committee

January 2008

The Year in Review

Team AGA tackled numerous industry issues on your behalf in 2007. Here is where we stood at year's end.



ENERGY LEGISLATION: Energy bill H.R. 6, which was signed into law Dec. 19, will not have a significant impact on natural gas utilities. We were able to remove the anti-supply provisions that were in the original House version and defeat the attempt to increase the depreciation period for natural gas distribution pipelines. On a positive note, H.R. 6 includes a provision requiring state public utility commissions to consider decoupling rate designs in rate cases. (See related story on p. 9.)

LIHEAP: Funding for the Low Income Home Energy Assistance Program for 2008 will be increased by approximately $408 million, bringing the total appropriation to just under $2.6 billion. This is the second-highest level of funding the program has ever received. (See related story on p. 32.)

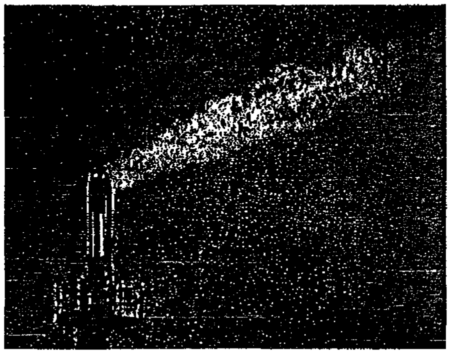
CLIMATE CHANGE BILL: While the passage of comprehensive climate change legislation is not likely in 2008, AGA will continue its strong advocacy efforts. Under the direction of the board-level Climate Change Task Force, AGA has adopted climate change principles, provided written comments and met with several key members of Congress and their staffs. AGA is developing provisions that will favorably position natural gas utilities in the national debate on climate change, and the association is finalizing the study "Blueprint for a Cleaner Future: Optimizing the Use of Natural Gas to Reduce Greenhouse Emissions." AGA also is working closely with the National Association of Regulatory Utility Commissioners and other strategic partners.

DIVIDEND TAXATION: Congress will consider the extension of the 15 percent tax rate on dividends as soon as 2008. AGA is coordinating efforts with utility shareholder and other groups and conducting research to bolster its case.

SAFETY LEADERSHIP SUMMIT: AGA continued to help educate members with best practices programs, conferences, teleconferences and workshops on topics ranging from uncollectibles to leak response. At AGA's first Safety Leadership Summit, industry CEOs and senior safety personnel shared best practices in employee, customer, contractor and pipeline safety.

LIEBERMAN-WARNER CLIMATE SECURITY ACT OF 2007 (S. 2191): S. 2191 was voted out of the Senate Committee on Environment and Public Works on Dec. 5. The AGA Executive

ERIN P. DOHERTY, AGA communications manager, may be reached at edoherty@aga.org.



Committee has met to discuss the ramifications of this legislation. The heart of the problem for local distribution companies is a provision that brings residential, commercial and small industrial natural gas customers under the cap-and-trade program and requires a 70 percent reduction in greenhouse gas emissions from natural gas by 2050.

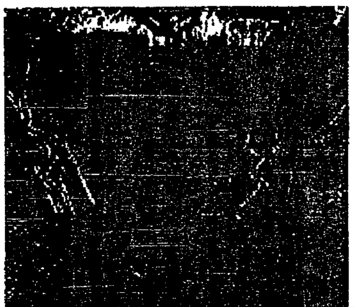
Earlier drafts of the Lieberman-Warner bill excluded natural gas utilities' customers. It is unrealistic to expect that a reduction in consumption of this magnitude can be attained by small-volume customers. Natural gas already offers more efficient and clean-burning energy than most other energy sources. Efficiency measures can further reduce natural gas consumption but not enough to meet these drastic goals. As a result, natural gas customers would be forced to compete for emission reduction credits with electric utilities and manufacturing facilities that will be turning to natural gas to help meet their own reduction goals.

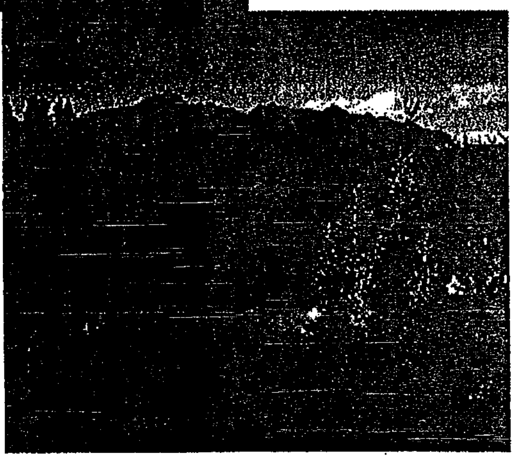
OUTER CONTINENTAL SHELF ACTIVITY: AGA is a strong advocate for the National Environment and Energy Development Act (H.R. 2784), which could open additional areas of the Outer Continental Shelf. Introduced by Reps. John Peterson, R-Pa., and Neil Abercrombie, D-Hawaii, the bill has bipartisan support with 165 co-sponsors; however, it lacks support from the House leadership.

AGA provided comments encouraging expanded natural gas production for the U.S. Department of Interior's five-year Oil and Gas Leasing Plan for the OCS. The new 2007 to 2012 plan opens new areas in the Gulf of Mexico and off Alaska for natural gas exploration and production. AGA supported the Bureau of Land Management's efforts to implement provisions of the Energy Policy Act of 2005, which allowed expanded production in Colorado and Wyoming. AGA also worked with the NARUC Gas Committee to pass a resolution providing for a full cost analysis of maintaining domestic production moratoria on federal lands.

DISTRIBUTION INTEGRITY MANAGEMENT: The U.S. Department of Transportation's proposed rule for the Distribution Integrity Management Program will be delayed until March 2008. AGA believes the rule will be aligned with its goal to obtain a reasonable regulation because we have provided extensive input into the rule framework as well as information from the guidance developed by the Gas Piping Technology Committee. AGA received a favorable interpretation on the treatment of casings in the transmission integrity management rule, including a deferred assessment on cased pipe.

AGA continues to work to reduce excavation damage, helping to launch the nationwide 811 "Call Before You Dig" telephone number and establish an excavation damage "Founders" group to advance state damage prevention improvements. We





have worked with the "Founders" to develop a framework for implementation of the excavation damage provisions of the Pipeline Safety Act.

ENVIRONMENTAL ISSUES: The California Climate Action Registry revised plans for its natural gas sector reporting protocol to reflect AGA's comments. We also made progress with EPA addressing the latest regional PCB concerns. In addition, EPA has agreed to negotiate an agreement with DOT to clarify which natural gas facilities will be exempt from EPA's oil spill prevention rules.

RESIDENTIAL FURNACES, BOILERS RULE: The Department of Energy issued a final rule for residential furnaces and boilers, which will ultimately result in greater energy efficiency and consumer choice. (See related story on p. 10.)

ENERGY EFFICIENCY SURVEY: AGA developed and disseminated information on the consumer response to natural gas price increases. A recent survey examined the nation's natural gas energy efficiency programs and local distribution company revenue decoupling. Forty-seven of AGA's 200 member companies, which serve more than half of U.S. residential natural gas customers, responded. At least 57 percent of U.S. natural gas residential customers are served by utilities that have an energy efficiency program.

AGA MEMBER SATISFACTION: AGA earned its highest marks to date on the annual membership satisfaction survey. Meetings and conferences met or exceeded attendance goals and yielded significant nondues revenue, which has helped fund priority initiatives, including the development of state utility shareholder organizations and AGA's "Blueprint for a Cleaner Future" study. Additionally, AGA has been awarded the opportunity to host LNG 17.

Tell Us About It!

Have a story idea or feedback on something you've read in *American Gas*? Let us know! Contact editor Stacey Bell at sbell7@tampabay.rr.com or 813/741-1772.

UNSG0571/07353

Looking Back on a Year's Worth of ROI

The monthly column reflects on key issues important to AGA members

THE CHALLENGE

PROVIDING AGA MEMBERS with quantitative and qualitative value far in excess of the dues they pay is the association's highest priority. In this regard, AGA realized two of its top advocacy goals in 2006: Congress appropriated a record $3.2 billion for the 2006 Low-Income Home Energy Assistance Program and extended until 2010 the 15 percent income tax rate on most dividend earnings and capital gains.

These advocacy activities, plus a few examples of the multitude of services AGA provided its members during the year, were highlighted in the 2006 *American Gas* "Return on Investment" columns and are summarized below.

THE RESULTS

A Leap for LIHEAP

AGA, a leading supporter of the federal Low-Income Home Energy Assistance Program (LIHEAP), used every means available to persuade Congress of the need to increase the program's fiscal 2006 funding.

The association stressed that the impact of rising energy prices is particularly harsh on low-income households and that more than 80 percent of the people eligible for LIHEAP don't receive the fuel-payment aid because the program's funding is inadequate. In response, Congress appropriated a record $3.2 billion for the 2006 LIHEAP. This compares with the $2.2 billion allotted for 2005.

AGA's successful effort means that $475 million more in LIHEAP funds were available in 2006 than in 2005 for low-income customers of member company utilities. The calculation is based on data showing that at least half of the people eligible for LIHEAP heat their homes with natural gas and AGA's utility members account for 83 percent of the gas delivered to U.S. households. (See May 2006 *American Gas*.)

A Victory for Investors

In 2003, Congress cut the federal income tax rate to 15 percent on dividends and capital gains, down from a top rate of 38.6 percent on dividend income and 20 percent on capital gains. The tax break was set to expire at the end of 2008.

AGA joined forces with the Alliance for Tax Fairness and Growth to support legislation extending the lower tax rates through 2010, which Congress passed in May. AGA's longer term goal is to see the tax cut made permanent.

> ***In fulfilling its role as a professional society, AGA holds numerous conferences, workshops and exhibitions that provide forums for the exchange of ideas and information.***

Compared with the original tax rates on dividend income, the 15 percent rate reduces the federal tax bite by an estimated $750 million annually for investors holding natural gas distribution company stocks. (See July 2006 *American Gas*.)

Addressing Natural Gas Pipe Standards and 'Rework'

A project to resolve quality-control issues related to the use of scrap resin, or "rework" material, in the manufacture of polyethylene (PE) natural gas pipe was

initiated by AGA's Plastic Materials Committee in 2002.

ASTM International's D-2513 PE gas pipe standard didn't limit the amount of rework material that may be used in the PE pipe manufacturing process. AGA believed the lack of an adequate standard could lead to mixing dirty, odd-shaped particles of rework resin with clean uniform virgin resin to produce PE pipe. This could result in imperfections or contamination within the pipe wall that create a potential initiation point for crack growth.

As a result of AGA's four-year rework project, the Plastics Pipe Institute (PPI) published "Requirements for the Use of Rework Materials in Manufacturing of Polyethylene Gas Pipe" (PPI Technical Note 30, 2006 edition). This set of guidelines states that no more than 30 percent of the resin used to make PE gas pipe shall be rework resin and includes quality-control steps designed to ensure contamination-free rework material. The 2006 PPI document will be included in the upcoming revised edition of AGA's "Plastic Pipe Manual." In addition, AGA expects the technical note will be incorporated by reference in ASTM's D-2513 standard by year's end.

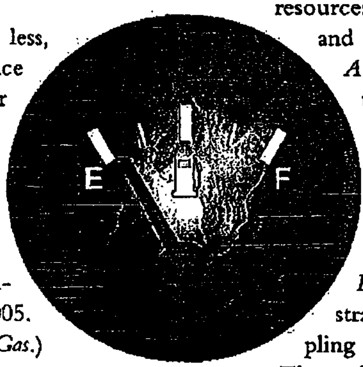
A collaborative effort of AGA,

researchers and PE pipe manufacturers, the rework project culminated in guidelines that enhance the safety and reliability of PE pipe and provide immeasurable long-term qualitative value to all of AGA's utility members. (See October 2006 *American Gas.*)

Doing More With Less

Shortly after moving its headquarters from Rosslyn, Va., to Washington, D.C., in 1999, AGA concluded it could reduce the size of the staff without hurting its effectiveness or compromising member service. Since the move, the number of employees has been reduced from 108 to 82. That left AGA with empty work stations, so the association reorganized its floor space to create a walled-off office area with a separate entrance that it sublet in 2005. In addition, AGA generates income by leasing office space to, and providing administrative services for, NGVAmerica and the Energy Solutions Center.

By doing more with less, consolidating empty space to fashion an office for sublet, and providing accommodations and services for the two gas-related entities, AGA has produced on ongoing annual savings of approximately $322,000 since 2005. (See June 2006 *American Gas.*)



Answering Your Call for Help

Close to 300 employees of AGA member companies took advantage of the association's SOS program in 2005. Through this service, a member company gains nearly immediate access to other members by sending AGA a detailed explanation of the information it is seeking about a business function, such as accounting, human resources or operating and engineering.

In turn, AGA relays the query via e-mail to the appropriate professionals at other member companies. The person initiating the SOS information request usually receives between eight and 30 responses, often within a day or two.

For the company seeking information, an individual SOS question-answer cycle is worth an estimated $5,000 to $20,000, based on the complexity of the inquiry and what it would cost a member to do the research itself or hire a consultant to gather the information from other gas utilities. Using a figure of $12,500—the mean of the range above—the 285 queries handled through AGA's SOS service in 2005 collectively saved the companies seeking information $3.6 million. (See April 2006 *American Gas.*)

Stay Informed: State Rate Actions

Answering member requests that it give greater priority to keeping them informed about state rate actions, issues and trends, AGA revamped its rate regulation web pages and developed new online resources, including *Rate Alert* and *Gas Rate Round-Up*. The *Alert* comes out weekly unless there's no news and provides summaries of gas utility rate case decisions as well as related materials and web links. The periodic *Round-Up* discusses rate strategies, such as decoupling mechanisms.

The redesigned web pages also are a source of other types of valuable information, including data on requested and allowed returns on equity, a consultant database and survey results on test-year lengths. In addition, AGA inaugurated a program of audioconferences on rate issues, which feature two or more speakers and a question-answer period.

Those who use AGA's rate and state regulation services attest to the enormous qualitative value in having a plethora of resources just a mouse click away and hearing via audioconferences what experts have to say about the hot rate issues of the day. (See August/ September 2006 *American Gas.*)

It Takes a Village

Utility consumer and community affairs (CCA) professionals are the first line of defense against eroding customer relations caused by higher natural gas bills.

Following the dramatic escalation of natural gas prices during the 2000-01 winter, some AGA members asked the association to focus more attention on CCA activities. In reply, AGA created a CCA Task Force that is open to all who wish to participate. The group provides a formal channel for the exchange of ideas and best practices by holding monthly teleconferences during which member companies talk about their successful CCA-related programs and answer questions.

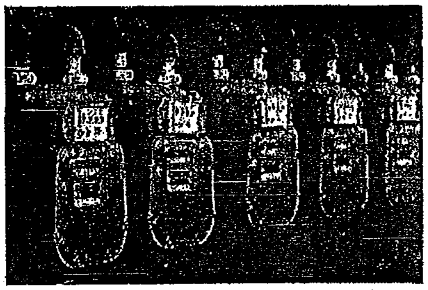
> ***Answering member requests that it give greater priority to keeping them informed about state rate actions, issues and trends, AGA revamped its rate regulation web pages and developed new online resources.***

The task force members say they are very pleased to have an inexpensive means (no travel involved) of discussing CCA strategies that provide gas customers with educational and financial tools to help them manage their fuel consumption and expenses. (See March 2006 *American Gas.*)

AGA/EEI Use DataSource Benchmarking To Improve Service

AGA joined forces with the Edison Electric Institute (EEI) in the mid-1990s to launch DataSource, an extensive database of utility information related to the performance of customer service tasks.

The data come from yearly questionnaires filled out by DataSource participants and cover call centers, meter-reading, billing, collections, cash posting, revenue protection, low-income programs, fleet management, field services, customer service website/customer information system, and commercial and industrial account management. The benchmarking results are available online to DataSource participants.



The benchmarking exercise is complemented by an annual AGA/EEI DataSource Best Practices Workshop at which DataSource participants discuss the techniques they've used to improve the efficiency of various customer service functions.

DataSource is a benefit of AGA membership. The fact that there's no charge to participate in the benchmarking exercise translates into a minimum yearly savings of $10,000 for each DataSource participant. This figure is at the low end of what private-sector firms charge for benchmarking services. (See November 2006 *American Gas*.)

A Better Balance

In fulfilling its role as a professional society, AGA holds numerous conferences, workshops and exhibitions that provide forums for the exchange of ideas and information.

At a recent AGA Uncollectibles Workshop, for example, South Jersey Gas Co. told the audience about its experience with a consulting firm's automated revenue miner, which matches utility customers' inactive accounts that have balances due with these same customers' active accounts. The utility reported that over a three-month period, the consulting firm identified $804,000 in overdue balances in inactive accounts that had features, such as Social Security numbers, similar to those of current customers. The utility determined that 87 percent of those inactive-active accounts were good matches and recovered 72 percent of the overdue balances.

Myriad information and ideas are presented at AGA meetings every year. It's impossible to calculate the savings AGA member companies realize by adopting these new ideas, but if the example above is any indication of the value of AGA's role as a professional society, the savings are substantial. (See February 2006 *American Gas*.)

another photo?

THE VALUE

THE AGA SERVICES highlighted here provided the association's full, limited and international members with a return of $479 million on their 2006 dues investment of $17.8 million. The 2006 return of nearly $27 for every $1 in membership dues illustrates clearly that AGA dues are an investment, not an expense.

**UNS GAS, INC.'S RESPONSE TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
May 7, 2009**

RUCO 1.48	Provide copies of the AGA dues invoices for the years 2007, 2008 and 2009.
RESPONSE:	Please see the PDF File RUCO 1.48 - AGA Invoices, Bates Nos. UNSG(0571)08823 to UNSG(0571)08825 on the enclosed CD for 2007, 2008, and 2009 AGA Invoices.
RESPONDENT:	Mina Briggs
WITNESS:	Gary Smith

02/26/2007 11:45 5208843606 CR PAGE 03

PO# 11790-1

AGA American Gas Association

Post Office Box 79226
Baltimore, Maryland 21279-0226
Telephone (202)824-7256
Fax (202)824-9156

UniSource Energy Corporation

2007 DUES

Year ending December 31, 2007

Full Member Company X Limited Member Company ____

A.G.A. Dues Rules are attached. Dues are based upon the following operating income information ($000):

2003 4,128 2004 15,658 2005 14,000 Average 11,262

YOUR 2006 DUES WERE .... $ 43,486

YOUR 2007 DUES ARE .... $ 45,508

1-17-07
UNS G
MB

2007 Payment Schedule

____ Full amount enclosed ____ Semi-annually (Jan.1, July 1)

____ Quarterly (Jan.1, Apr.1, July 1, Oct.1) ____ Other (Please state)

return ck to Foltz or Hatfield

Please return this completed form to the A.G.A. Treasurer at the above address. Payments may also be directed to the address noted above.

Invoice to: .... Approved: ....

.... Title ....

.... Date: ....

....

Phone: ( )........... - .... Fax ( )........... - ....

notify sfoltz@tep.com

IMPORTANT IRS REQUIRED NOTICE

Federal regulations require us to advise you that contributions or gifts to the American Gas Association are not deductible as charitable contributions for federal income tax purposes. Dues payments are usually deductible by members as an ordinary and necessary business expense. The American Gas Association expects that a portion of your dues may be used to influence legislation. **The Association will pay directly the federal tax that is due on lobbying activities.**

Dues include a one-year subscription to *American Gas*, the normal subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers.

PAGE 3/3 * RCVD AT 2/26/2007 11:49:25 AM [US Mountain Standard Time] * SVR:TEPFAX/10 * DNIS:429 * CSID:5208843606 * DURATION (mm-ss):01-16

01/10/2008 10:16 5208843606 CR PAGE 02

American Gas Association

Post Office Box 79226
Baltimore, Maryland 21279-0226
Telephone (202)824-7256
Fax (202)824-9156

UniSource Energy Corporation

PO# 11790-2

2008 DUES

Year ending December 31, 2008

Full Member Company X Limited Member Company ____

A.G.A. Dues Rules are attached. Dues are based upon the following operating income information ($000):

2004 15,658 2005 14,000 2006 14,000 Average 14,553

YOUR 2007 DUES WERE .... $ 45,508

YOUR 2008 DUES ARE .... $ 47,879

UNSG MB 1-8-08

req'd

2008 Payment Schedule

______ Full amount enclosed ______ Semi-annually (Jan.1, July 1)

______ Quarterly (Jan.1, Apr.1, July 1, Oct.1) ______ Other (Please state)

on notification return ck to Foltz UE102

Please return this completed form to the A.G.A. Treasurer at the above address. Payments may also be directed to the address noted above.

Invoice to: .... Approved: ....

.... Title ....

.... Date: ....

....

Phone: ( ) .... - .... Fax ( ) .... - ....

IMPORTANT IRS REQUIRED NOTICE

Federal regulations require us to advise you that contributions or gifts to the American Gas Association are not deductible as charitable contributions for federal income tax purposes. Dues payments are usually deductible by members as an ordinary and necessary business expense. The American Gas Association expects that a portion of your dues may be used to influence legislation. **It is estimated that approximately four percent of your dues may be non-deductible as an ordinary and necessary business expense.** The Association will inform you if the actual non-deductible amount materially exceeds this estimate.

Dues include a one-year subscription to ***American Gas***, the normal subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers.

PAGE 1/1 * RCVD AT 1/10/2008 10:24:44 AM [US Mountain Standard Time] * SVR:TEPFAX/0 * DNIS:429 * CSID:5208843606 * DURATION (mm-ss):01-02

01/14/2009 08:58 5208843606 CR PAGE 01

PO# 11790-3

AGA
American Gas Association

Post Office Box 79226
Baltimore, Maryland 21279-0226
Telephone (202)824-7256
Fax (202)824-9156

UniSource Energy Corporation

Ben - please process PO to pay immediately. Thanks

B

5-13-08

UNSGmb

2009 DUES

Year ending December 31, 2009

Full Member Company X   Limited Member Company ___

A.G.A. Dues Rules are attached. Dues are based upon the following operating income information ($000):

2005 14,000   2006 14,000   2007 13,000   Average 13,667

YOUR 2008 DUES WERE .... $ 47,879

YOUR 2009 DUES ARE .... $ 51,901

2009 Payment Schedule

✓ Full amount enclosed   ___ Semi-annually (Jan.1, July 1)

___ Quarterly (Jan.1, Apr.1, July 1, Oct.1)   ___ Other (Please state)

Please return this completed form to the A.G.A. Treasurer at the above address. Payments may also be directed to the address noted above.

Invoice to: ....   Approved: ....

....   Title ....

....   Date: ....

....

Phone: ( )........ - ....   Fax ( )........ - ....

IMPORTANT IRS REQUIRED NOTICE

Federal regulations require us to advise you that contributions or gifts to the American Gas Association are not deductible as charitable contributions for federal income tax purposes. Dues payments are usually deductible by members as an ordinary and necessary business expense. The American Gas Association expects that a portion of your dues may be used to influence legislation. **It is estimated that approximately four percent of your dues may be non-deductible as an ordinary and necessary business expense.** The Association will inform you if the actual non-deductible amount materially exceeds this estimate.

Dues include a one-year subscription to *American Gas*, the normal subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers.

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AGA American Gas Association

Post Office Box 79226
Baltimore, Maryland 21279-0226
Telephone (202)824-7256
Fax (202)824-9156

UniSource Energy Corporation

PO# 11790-2

Remove 4% for Lobbying

2008 DUES

Year ending December 31, 2008

Full Member Company X Limited Member Company ___

A.G.A. Dues Rules are attached. Dues are based upon the following operating income information ($000):

2004 15,658 2005 14,000 2006 14,000 Average 14,553

YOUR 2007 DUES WERE .... $ 45,508

YOUR 2008 DUES ARE .... $ 47,879

UNSG MB
rec'd 1-8-08

2008 Payment Schedule

___ Full amount enclosed ___ Semi-annually (Jan.1, July 1)

___ Quarterly (Jan.1, Apr.1, July 1, Oct.1) ___ Other (Please state)

Return to Foltz UE102 on notification

Please return this completed form to the A.G.A. Treasurer at the above address. Payments may also be directed to the address noted above.

Invoice to: .... Approved: ....

.... Title ....

.... Date: ....

....

Phone: ( ).......... - .... Fax ( ).......... - ....

IMPORTANT IRS REQUIRED NOTICE

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Dues include a one-year subscription to *American Gas*, the normal subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers.

PAGE 1/1 * RCVD AT 1/10/2008 10:24:44 AM [US Mountain Standard Time] * SVR:TEPFAX/0 * DNIS:429 * CSID:5208843606 * DURATION (mm-ss):01-02

24

UNS GAS, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2008

ADJUSTMENT NAME:	Normalize Outside Legal Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	September 30, 2008
PREPARED BY:	Mina Briggs & Janet Zaidenberg-Schrum JZS 9/30/08
CHECKED BY:	Mina Briggs & Janet Zaidenberg-Schrum MB 9/30/08
REVIEWED BY:	Dallas Dukes DD

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
		✓	
923	Outside Services Employed 1a	$305,984	
	ENTRY TOTAL	$305,984	$0
	NET ENTRY		($305,984)

Reason for Adjustment

To normalize outside legal expense for the test year. ✓

9/30/2008 12:09 PM

UNS Gas, Inc.
Legal Expenses - 3 Year Average
Test Year Ended June 30, 2008

Task	Task Description		Test Year		2007		2006		2005			
GTP0923	Admin & General Salaries	2.3A	$5,778.57	3.3A	$13,010.60	4.2A	$12,460.02	5.2A	$28,830.40			
GTPA160	Legal: El Paso Gas Allocation		$99,887.50		$196,203.43		$395,246.86		$361,232.89			
GTPD160	Legal: PGA Application		$0.00		$3.00		$27,722.06		$68,901.93			
GTPF160	Legal: UNSG Santa Cruz Gomez v. Cabrera, et al		$14,536.76		$52,916.35		$18,927.03		$690.00			
GTPH160	Legal: Allstate v UES-Gas		$602.42		$602.42		$0.00		$0.00			
UNG06RC	UNS Gas Rate Case-2006		$310,060.91		$307,303.51 c		$0.00		$0.00			
	All other - JE, Accruals, Reversals		($36,353.00)		($21,041.50)		($15,815.35)		$28,724.86			
			$394,513.16		$548,999.81		$438,540.62		$488,380.08	$1,475,920.51	b	
									3 Year Average	$491,973.50	Including the Rate Case Exp. Write-off	

Removed through Proforma Adjustments		
DSM Proforma Adjustment	$897.00	2.3B
Misc. Proforma Adjustment - 2006 Rate Case Exp	$310,060.91	
	$310,957.91	
Amount Left In Test Year for Legal for Legal	**$83,555.25**	2.3C

3 Year Average - Expense for Test Year	① $389,539.00	Excluding the Rate Case Exp. Write-off	
Test Yr. Level After Other Adjustments	($83,555.25)	2.3C	
Adjustment for Recurring Legal Expense	**$305,983.75**	a	

$① = \frac{b - c}{3}$

$ 1,475,920.51
(307,303.51)
$ 1,168,617.00
÷ 3
$ 389,539

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UNSG0571/02564

UNS GAS - TEST YEAR LEGAL EXPENSES

Company:032
Expenditure Type:152 - Legal Expense
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name	
MAR-08	0908	52010	GCIFDSM		Purchase Invoices USD	224.25		224.25	35663	ROSHKA DEWULF & PATTEN PLC	Removed
MAR-08	0908	52010	GEHHDSM		Purchase Invoices USD	224.25		224.25	35663	ROSHKA DEWULF & PATTEN PLC	with DSM
MAR-08	0908	52010	GESHDSM		Purchase Invoices USD	224.25		224.25	35663	ROSHKA DEWULF & PATTEN PLC	Proforma
MAR-08	0908	52010	GWEADSM		Purchase Invoices USD	$224.25		$224.25	35663	ROSHKA DEWULF & PATTEN PLC	Adjustment
	Sum					$897.00		$897.00			
AUG-07	0923	52010	GTP0923		Purchase Invoices USD	$853.20		$853.20	34588	ROSHKA DEWULF & PATTEN PLC	
OCT-07	0923	52010	GTP0923		Purchase Invoices USD	$10.80		$10.80	34924	ROSHKA DEWULF & PATTEN PLC	
NOV-07	0923	52010	GTP0923		Purchase Invoices USD	$62.00		$62.00	35078	ROSHKA DEWULF & PATTEN PLC	
NOV-07	0923	52010	GTP0923		Purchase Invoices USD	$1,644.85		$1,644.85	35077	ROSHKA DEWULF & PATTEN PLC	
DEC-07	0923	52010	GTP0923		Purchase Invoices USD	$1,787.02		$1,787.02	35121	ROSHKA DEWULF & PATTEN PLC	
DEC-07	0923	52010	GTP0923		Purchase Invoices USD	$8.00		$8.00	35114	ROSHKA DEWULF & PATTEN PLC	
JAN-08	0923	52010	GTP0923		Purchase Invoices USD	321.40		321.40	35405	ROSHKA DEWULF & PATTEN PLC	
MAR-08	0923	52010	GTP0923		Purchase Invoices USD	58.50		$58.50	35663	ROSHKA DEWULF & PATTEN PLC	
MAR-08	0923	52010	GTP0923		Purchase Invoices USD	1,152.80		$1,152.80	35536	ROSHKA DEWULF & PATTEN PLC	
MAY-08	0923	52010	GTP0923		Purchase Invoices USD	30.00		$30.00	043008 11744572	ROSHKA DEWULF & PATTEN PLC	
AUG-07	0923	52010	GTP0923	LA POSADA HOTEL			150.00	($150.00)			
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	16,761.50		$16,761.50	645312	LOCKE LIDDELL & SAPP LLP	
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	9,350.00		9,350.00	642031	LOCKE LIDDELL & SAPP LLP	
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	4,502.50		4,502.50	625723	LOCKE LIDDELL & SAPP LLP	
OCT-07	0923	52010	GTPA160		Purchase Invoices USD	2,515.00		2,515.00	648068	LOCKE LIDDELL & SAPP LLP	
OCT-07	0923	52010	GTPA160		Purchase Invoices USD	30,484.35		30,484.35	635624	LOCKE LIDDELL & SAPP LLP	
NOV-07	0923	52010	GTPA160		Purchase Invoices USD	3,045.00		3,045.00	652514	LOCKE LIDDELL & SAPP LLP	
DEC-07	0923	52010	GTPA160		Purchase Invoices USD	447.69		447.69	660040	LOCKE LIDDELL & SAPP LLP	
DEC-07	0923	52010	GTPA160		Purchase Invoices USD	27,971.50		27,971.50	656799	LOCKE LIDDELL & SAPP LLP	
FEB-08	0923	52010	GTPA160		Purchase Invoices USD	2,712.50		2,712.50	663814	LOCKE LIDDELL & SAPP LLP	
MAR-08	0923	52010	GTPA160		Purchase Invoices USD	32.46		32.46	666730A	LOCKE LIDDELL & SAPP LLP	
MAR-08	0923	52010	GTPA160		Purchase Invoices USD	1,032.50		1,032.50	666730	LOCKE LIDDELL & SAPP LLP	
JUN-08	0923	52010	GTPA160		Purchase Invoices USD	1,032.50		1,032.50	674225	LOCKE LIDDELL & SAPP LLP	
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	1,077.80		1,077.80	40642001008080?	BEALE MICHEAELS & SLACK PC	
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	4,808.84		4,808.84	40642001007250?	BEALE MICHEAELS & SLACK PC	
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	7,728.27		7,728.27	062707 40642-0010	BEALE MICHEAELS & SLACK PC	
OCT-07	0923	52010	GTPF160		Purchase Invoices USD	161.85		161.85	12106	INVESTIGATIVE RESEARCH INC	
OCT-07	0923	52010	GTPF160		Purchase Invoices USD	137.50		137.50	100507 40642	BEALE MICHEAELS & SLACK PC	
NOV-07	0923	52010	GTPF160		Purchase Invoices USD	500.00		500.00	40642001011307	BEALE MICHEAELS & SLACK PC	
JAN-08	0923	52010	GTPF160		Purchase Invoices USD	60.00		60.00	TEP2008-1	LESHER & CORRADINI	
MAR-08	0923	52010	GTPF160		Purchase Invoices USD	62.50		62.50	02208 6612203	BEALE MICHEAELS & SLACK PC	
AUG-07	0923	52010	GTPH160		Purchase Invoices USD	142.60		142.60	51269	PRODOX LLC	
AUG-07	0923	52010	GTPH160		Purchase Invoices USD	126.18		126.18	51157	PRODOX LLC	
SEP-07	0923	52010	GTPH160		Purchase Invoices USD	92.85		92.85	52020	PRODOX LLC	
DEC-07	0923	52010	GTPH160		Purchase Invoices USD	90.79		90.79	TEP2012-7	LESHER & CORRADINI	
JUL-07	0923	52010	GTPH160	LA POSADA HOTEL		150.00		150.00			
DEC-07	0923	52010	UNG06RC		Purchase Invoices USD	15,661.35		15,661.35	35117	ROSHKA DEWULF & PATTEN PLC	
JAN-08	0923	52010	UNG06RC		Purchase Invoices USD	1,369.40		1,369.40	35402	ROSHKA DEWULF & PATTEN PLC	
MAR-08	0923	52010	UNG06RC		Purchase Invoices USD	1,150.50		1,150.50	35663	ROSHKA DEWULF & PATTEN PLC	
MAY-08	0923	52010	UNG06RC		Purchase Invoices USD	237.50		237.50	043008 11744572	ROSHKA DEWULF & PATTEN PLC	
MAR-08	0923	52010			Accrual USD APR-08	0.53		0.53			
JUL-07	0923	52010			Accrual USD AUG-07	0.53		0.53			
NOV-07	0923	52010			Accrual USD DEC-07	0.53		0.53			
JAN-08	0923	52010			Accrual USD FEB-08	0.53		0.53			
JUN-08	0923	52010			Accrual USD JUL-08	0.53		0.53			
MAY-08	0923	52010			Accrual USD JUN-08	0.53		0.53			

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UNSG0571/02565

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UNS GAS - TEST YEAR LEGAL EXPENSES

Company:032
Expenditure Type:152 - Legal Expense
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
FEB-08	0923	52010			Accrual USD MAR-08	1,065.49		1,065.49		
APR-08	0923	52010			Accrual USD MAY-08	0.53		0.53		
OCT-07	0923	52010			Accrual USD NOV-07	0.53		0.53		
SEP-07	0923	52010			Accrual USD OCT-07	0.53		0.53		
AUG-07	0923	52010			Accrual USD SEP-07	0.53		0.53		
SEP-07	0923	52010			J341 - Legal Accrual Accrual USD		6,250.00	(6,250.00)		
DEC-07	0923	52010			J341 AP Legal Accrual Adjustment	29,000.00		29,000.00		
FEB-08	0923	52010			J341 AP Legal Accrual Adjustment	28,000.00		28,000.00		
MAR-08	0923	52010			J356 - Reverses "J341 AP Legal Accrual Adjustment USD"02-APR-08		28,000.00	(28,000.00)		
FEB-08	0923	52010			J356 - Reverses "J341 AP Legal Accrual Adjustment USD"04-MAR-08		29,000.00	(29,000.00)		
JUL-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 01-AUG-07 13:44:15	0.00		0.00		
DEC-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 03-JAN-08 08:07:01	0.00		0.00		
FEB-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 03-MAR-08 10:58:16	0.00		0.00		
JAN-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 08-FEB-08 07:53:43	0.00		0.00		
SEP-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 28-SEP-07 08:12:09	0.00		0.00		
AUG-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 29-AUG-07 08:38:45	0.00		0.00		
APR-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-APR-08 08:07:32	0.00		0.00		
JUN-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-JUN-08 07:59:47	0.00		0.00		
MAY-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-MAY-08 11:26:40	0.00		0.00		
NOV-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-NOV-07 08:26:08	0.00		0.00		
OCT-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-OCT-07 14:27:59	0.00		0.00		
MAR-08	0923	52010			J817 UES UBOC Debt Cost Amtz: 31-MAR-08 08:04:51	0.00		0.00		
NOV-07	0923	52010			J916 Reclass Rate Case Co	16,756.40		16,756.40		
OCT-07	0923	52010			J917 Write Down UNG Rate	128,383.06		128,383.06		
SEP-07	0923	52010			J949 Adjust Rate Case Cos	146,502.70		146,502.70		
DEC-07	0923	52010			J975 Reverse 3rd Quarter Adjustment		31,000.00	(31,000.00)		
APR-08	0923	52010			Reverses "Accrual USD APR-08"22-APR-08 14:21:19		0.53	(0.53)		
AUG-07	0923	52010			Reverses "Accrual USD AUG-07"30-AUG-07 10:55:42		0.53	(0.53)		
DEC-07	0923	52010			Reverses "Accrual USD DEC-07"31-DEC-07 13:45:17		0.53	(0.53)		
FEB-08	0923	52010			Reverses "Accrual USD FEB-08"04-		0.53	(0.53)		
JUL-07	0923	52010			Reverses "Accrual USD JUL-07"26-		0.53	(0.53)		
JUN-08	0923	52010			Reverses "Accrual USD JUN-08"25-		0.53	(0.53)		
MAR-08	0923	52010			Reverses "Accrual USD MAR-08"26-MAR-08 13:15:52		1,065.49	(1,065.49)		

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UNS GAS - TEST YEAR LEGAL EXPENSES

Company:032
Expenditure Type:152 - Legal Expense
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
MAY-08	0923	52010			Reverses "Accrual USD MAY-08"27-MAY-08 15:28:51		0.53	(0.53)		
NOV-07	0923	52010			Reverses "Accrual USD NOV-07"27-NOV-07 13:42:47		0.53	(0.53)		
OCT-07	0923	52010			Reverses "Accrual USD OCT-07"26-		0.53	(0.53)		
SEP-07	0923	52010			Reverses "Accrual USD SEP-07"20-SEP-07 10:41:01		0.53	(0.53)		
	Sum					489,086.95	95,470.79	393,616.16		
Total						489,983.95	95,470.79	394,513.16		

Task	Task Description		
GTP0923	Admin & General Salaries	$5,778.57	A
GTPA160	Legal: El Paso Gas Allocation	$99,887.50	
GTPF160	Legal: UNSG Santa Cruz Gomez v. Cabrera, et al.	$14,536.76	
GTPH160	Legal: Allstate v UES-Gas	$602.42	
UNG06RC	UNS Gas Rate Case 2006	$310,060.91	
	All other - JE, Accruals, Reversals	($36,353.00)	
		$394,513.16	
	Removed through Proforma		
	DSM Proforma Adjustment	$897.00	B
	Misc. Proforma Adjustment - 2006	$310,060.91	
		$310,957.91	
	Amount Left In Test Year for Legal	**$83,555.25**	C

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UNS Gas Legal Expenses - 2007

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
JAN-07	0923	52010	GTP0923		Purchase Invoices USD	413.00		413.00	33616	ROSHKA DEWULF & PATTEN PLC
JAN-07	0923	52010	GTP0923		Purchase Invoices USD	2,508.00		2,508.00	6957465	THELEN REID BROWN RAYSMAN & STEINER LLP
APR-07	0923	52010	GTP0923		Purchase Invoices USD	1,778.32		1,778.32	7300913	THELEN REID BROWN RAYSMAN & STEINER LLP
APR-07	0923	52010	GTP0923		Purchase Invoices USD	$1,518.75		$1,518.75	6964015	THELEN REID BROWN RAYSMAN & STEINER LLP
APR-07	0923	52010	GTP0923		Purchase Invoices USD	$560.00		$560.00	34026	ROSHKA DEWULF & PATTEN PLC
APR-07	0923	52010	GTP0923		Purchase Invoices USD	$53.06		$53.06	801752	LEWIS AND ROCA LLP
MAY-07	0923	52010	GTP0923		Purchase Invoices USD	$1,783.60		$1,783.60	34163	ROSHKA DEWULF & PATTEN PLC
JUN-07	0923	52010	GTP0923		Purchase Invoices USD	$180.00		$180.00	0507	MELISSA PIGNATELLI O BRIEN
AUG-07	0923	52010	GTP0923		Purchase Invoices USD	$853.20		$853.20	34588	ROSHKA DEWULF & PATTEN PLC
AUG-07	0923	52010	GTP0923	LA POSADA HOTEL			$150.00	($150.00)		
OCT-07	0923	52010	GTP0923		Purchase Invoices USD	$10.80		$10.80	34924	ROSHKA DEWULF & PATTEN PLC
NOV-07	0923	52010	GTP0923		Purchase Invoices USD	62.00		62.00	35078	ROSHKA DEWULF & PATTEN PLC
NOV-07	0923	52010	GTP0923		Purchase Invoices USD	1,644.85		$1,644.85	35077	ROSHKA DEWULF & PATTEN PLC
DEC-07	0923	52010	GTP0923		Purchase Invoices USD	8.00		$8.00	35114	ROSHKA DEWULF & PATTEN PLC
DEC-07	0923	52010	GTP0923		Purchase Invoices USD	1,787.02		$1,787.02	35121	ROSHKA DEWULF & PATTEN PLC
JAN-07	0923	52010	GTPA160		Purchase Invoices USD	37,955.10		$37,955.10	615738	LOCKE LIDDELL & SAPP LLP
FEB-07	0923	52010	GTPA160		Purchase Invoices USD	22,095.10		$22,095.10	618248	LOCKE LIDDELL & SAPP LLP
MAR-07	0923	52010	GTPA160		Purchase Invoices USD	22,950.69		22,950.69	622206	LOCKE LIDDELL & SAPP LLP
MAY-07	0923	52010	GTPA160		Purchase Invoices USD	12,760.00		12,760.00	629548	LOCKE LIDDELL & SAPP LLP
JUN-07	0923	52010	GTPA160		Purchase Invoices USD	5,365.00		5,365.00	633230	LOCKE LIDDELL & SAPP LLP
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	16,761.50		16,761.50	645312	LOCKE LIDDELL & SAPP LLP
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	9,350.00		9,350.00	642031	LOCKE LIDDELL & SAPP LLP
SEP-07	0923	52010	GTPA160		Purchase Invoices USD	4,502.50		4,502.50	625723	LOCKE LIDDELL & SAPP LLP
OCT-07	0923	52010	GTPA160		Purchase Invoices USD	2,515.00		2,515.00	648068	LOCKE LIDDELL & SAPP LLP
OCT-07	0923	52010	GTPA160		Purchase Invoices USD	30,484.35		30,484.35	635624	LOCKE LIDDELL & SAPP LLP
NOV-07	0923	52010	GTPA160		Purchase Invoices USD	3,045.00		3,045.00	652514	LOCKE LIDDELL & SAPP LLP
DEC-07	0923	52010	GTPA160		Purchase Invoices USD	27,971.50		27,971.50	656799	LOCKE LIDDELL & SAPP LLP
DEC-07	0923	52010	GTPA160		Purchase Invoices USD	447.69		447.69	660040	LOCKE LIDDELL & SAPP LLP
JAN-07	0923	52010	GTPD160		Purchase Invoices USD	3.00		3.00	33616	ROSHKA DEWULF & PATTEN PLC
JAN-07	0923	52010	GTPF160		Purchase Invoices USD	837.50		837.50	121106 40642-0010	BEALE MICHEAELS & SLACK PC
JAN-07	0923	52010	GTPF160		Purchase Invoices USD	3,810.81		3,810.81	406420010010407	BEALE MICHEAELS & SLACK PC
JAN-07	0923	52010	GTPF160		Purchase Invoices USD	143.90		143.90	11732	INVESTIGATIVE RESEARCH INC
FEB-07	0923	52010	GTPF160		Purchase Invoices USD	3,245.04		3,245.04	020707 324504	BEALE MICHEAELS & SLACK PC
MAR-07	0923	52010	GTPF160		Purchase Invoices USD	320.15		320.15	7628	BOULEY & SCHIPPERS
MAR-07	0923	52010	GTPF160		Purchase Invoices USD	600.00		600.00	030707 60000	MIRNA GALLEGO
APR-07	0923	52010	GTPF160		Purchase Invoices USD	377.00		377.00	032707 37700	MIRNA GALLEGO
APR-07	0923	52010	GTPF160		Purchase Invoices USD	300.00		300.00	032707 30000	MIRNA GALLEGO
APR-07	0923	52010	GTPF160		Purchase Invoices USD	821.85		821.85	7654	BOULEY & SCHIPPERS
APR-07	0923	52010	GTPF160		Purchase Invoices USD	837.00		837.00	7605	BOULEY & SCHIPPERS
APR-07	0923	52010	GTPF160		Purchase Invoices USD	13,402.91		13,402.91	041907 40642-0010	BEALE MICHEAELS & SLACK PC
APR-07	0923	52010	GTPF160		Purchase Invoices USD	8,200.00		8,200.00	030607 40642-0010	BEALE MICHEAELS & SLACK PC
MAY-07	0923	52010	GTPF160		Purchase Invoices USD	4,209.60		4,209.60	406420010050407	BEALE MICHEAELS & SLACK PC
JUN-07	0923	52010	GTPF160		Purchase Invoices USD	225.00		225.00	2007-1261	ISABEL FIERROS
JUN-07	0923	52010	GTPF160		Purchase Invoices USD	0.00		0.00	2007/1261CANCELLE	ISABEL FIERROS
JUN-07	0923	52010	GTPF160		Purchase Invoices USD	1,173.33		1,173.33	63	THOMAS A ZLAKET PLLC
JUN-07	0923	52010	GTPF160		Purchase Invoices USD	0.00		0.00	63 cancelled	THOMAS A ZLAKET PLLC
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	7,728.27		7,728.27	082707 40642-0010	BEALE MICHEAELS & SLACK PC
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	4,808.84		4,808.84	406420010072607	BEALE MICHEAELS & SLACK PC
AUG-07	0923	52010	GTPF160		Purchase Invoices USD	1,077.80		1,077.80	406420010080607	BEALE MICHEAELS & SLACK PC
OCT-07	0923	52010	GTPF160		Purchase Invoices USD	161.85		161.85	12105	INVESTIGATIVE RESEARCH INC
OCT-07	0923	52010	GTPF160		Purchase Invoices USD	137.50		137.50	100507 40642	BEALE MICHEAELS & SLACK PC

UNS Gas Legal Expenses - 2007

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
NOV-07	0923	52010	GTPF160		Purchase Invoices USD	500.00		500.00	406420010111307	BEALE MICHEAELS & SLACK PC
JUL-07	0923	52010	GTPH160	LA POSADA HOTEL		150.00		150.00		
AUG-07	0923	52010	GTPH160		Purchase Invoices USD	126.18		126.18	51157	PRODOX LLC
AUG-07	0923	52010	GTPH160		Purchase Invoices USD	142.60		142.60	51269	PRODOX LLC
SEP-07	0923	52010	GTPH160		Purchase Invoices USD	92.85		92.85	52620	PRODOX LLC
DEC-07	0923	52010	GTPH160		Purchase Invoices USD	90.79		90.79	TEP2012-7	LESHER & CORRADINI
DEC-07	0923	52010	UNG06RC		Purchase Invoices USD	15,661.35		15,661.35	35117	ROSHKA DEWULF & PATTEN PLC
MAR-07	0923	52010			Accrual USD APR-07	0.53		0.53		
JUL-07	0923	52010			Accrual USD AUG-07	0.53		0.53		
NOV-07	0923	52010			Accrual USD DEC-07	0.53		0.53		
JAN-07	0923	52010			Accrual USD FEB-07	0.53		0.53		
JUN-07	0923	52010			Accrual USD JUL-07	0.53		0.53		
MAY-07	0923	52010			Accrual USD JUN-07	0.53		0.53		
FEB-07	0923	52010			Accrual USD MAR-07	0.53		0.53		
APR-07	0923	52010			Accrual USD MAY-07	0.53		0.53		
OCT-07	0923	52010			Accrual USD NOV-07	0.53		0.53		
SEP-07	0923	52010			Accrual USD OCT-07	0.53		0.53		
AUG-07	0923	52010			Accrual USD SEP-07	0.53		0.53		
MAR-07	0923	52010			J341 - Legal Accrual Accrual USD		13,000.00	(13,000.00)		
MAR-07	0923	52010			J341 - Legal Accrual Accrual USD	54,000.00		54,000.00		
JUN-07	0923	52010			J341 - Legal Accrual Accrual USD		50,350.00	(50,350.00)		
SEP-07	0923	52010			J341 - Legal Accrual Accrual USD		6,250.00	(6,250.00)		
DEC-07	0923	52010			J341 AP Legal Accrual Adjustment USD	29,000.00		29,000.00		
JUL-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 01-AUG-07 13:44:15	0.00		0.00		
DEC-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 03-JAN-08 08:07:01	0.00		0.00		
APR-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 27-APR-07 08:41:12		3,297.07	(3,297.07)		
SEP-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 28-SEP-07 08:12:09	0.00		0.00		
AUG-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 29-AUG-07 08:38:45	0.00		0.00		
JUN-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 29-JUN-07 11:31:30	3,297.07		3,297.07		
MAY-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-MAY-07 08:13:17		3,297.07	(3,297.07)		
NOV-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-NOV-07 08:26:08	0.00		0.00		
OCT-07	0923	52010			J817 UES UBOC Debt Cost Amtz: 30-OCT-07 14:27:59	0.00		0.00		
JAN-07	0923	52010			J908 - Reverses "J960 Additional TEP/UNG/U Adjustment USD"12-FEB-07 09:15:31		143.90	(143.90)		
NOV-07	0923	52010			J916 Reclass Rate Case Co Adjustment USD	16,756.40		16,756.40		
OCT-07	0923	52010			J917 Write Down UNG Rate Adjustment USD	128,383.06		128,383.06		
SEP-07	0923	52010			J949 Adjust Rate Case Cos Adjustment USD	146,502.70		146,502.70		

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UNS Gas Legal Expenses - 2007

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
DEC-07	0923	52010			J975 Reverse 3rd Quarter Adjustment USD		31,000.00	(31,000.00)		
APR-07	0923	52010			Reverses "Accrual USD APR-07"24-APR-07 10:38:11		0.53	(0.53)		
AUG-07	0923	52010			Reverses "Accrual USD AUG-07"30-AUG-07 10:55:42		0.53	(0.53)		
DEC-07	0923	52010			Reverses "Accrual USD DEC-07"31-DEC-07 13:45:17		0.53	(0.53)		
FEB-07	0923	52010			Reverses "Accrual USD FEB-07"06-MAR-07 11:52:08		0.53	(0.53)		
JAN-07	0923	52010			Reverses "Accrual USD JAN-07"06-FEB-07 07:33:17		0.53	(0.53)		
JUL-07	0923	52010			Reverses "Accrual USD JUL-07"26-JUL-07 11:09:41		0.53	(0.53)		
JUN-07	0923	52010			Reverses "Accrual USD JUN-07"22-JUN-07 13:00:59		0.53	(0.53)		
MAR-07	0923	52010			Reverses "Accrual USD MAR-07"27-MAR-07 12:17:04		0.53	(0.53)		
MAY-07	0923	52010			Reverses "Accrual USD MAY-07"30-MAY-07 15:01:41		0.53	(0.53)		
NOV-07	0923	52010			Reverses "Accrual USD NOV-07"27-NOV-07 13:42:47		0.53	(0.53)		
OCT-07	0923	52010			Reverses "Accrual USD OCT-07"26-OCT-07 10:57:25		0.53	(0.53)		
SEP-07	0923	52010			Reverses "Accrual USD SEP-07"20-SEP-07 10:41:01		0.53	(0.53)		
		Sum				656,494.21	107,494.40	548,999.81		
Total						656,494.21	107,494.40	548,999.81		

Task	Task Description	
GTP0923	Admin & General Salaries	$13,010.60 A
GTPA160	Legal: El Paso Gas Allocation	$196,203.43
GTPD160	Legal: PGA Application	$3.00
GTPF160	Legal: UNSG Santa Cruz Gomez v. Cabrera, et al.	$52,918.35
GTPH160	Legal: Allstate v UES-Gas	$502.42
UNG06RC	UNS Gas Rate Case 2006	$307,303.51
	All other - JE, Accruals, Reversals	($21,041.50)
		$548,999.81
	2006 Rate Case - write off	$307,303.51 8a (3.2)
	Without Rate Case Write off	$241,696.30

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UNS Gas Legal Expenses - 2006

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
MAR-06	0923	52010	G560930		Purchase Invoices USD	55.36		55.36	RPC51257LUCERO	PETTY CASH
FEB-06	0923	52010	GTP0923		Purchase Invoices USD	2,233.75		2,233.75	0106 7052065	ROSHKA DEWULF & PATTEN PLC
APR-06	0923	52010	GTP0923		Purchase Invoices USD	1,386.60		1,386.60	0306 8497530	ROSHKA DEWULF & PATTEN PLC
APR-06	0923	52010	GTP0923		Purchase Invoices USD	$71.45		$71.45	764891	LEWIS AND ROCA LLP
MAY-06	0923	52010	GTP0923		Purchase Invoices USD	$453.20		$453.20	053106 5737731	ROSHKA DEWULF & PATTEN PLC
JUL-06	0923	52010	GTP0923		Purchase Invoices USD	$115.45		$115.45	770751	LEWIS AND ROCA LLP
JUL-06	0923	52010	GTP0923		Purchase Invoices USD	$26.62		$26.62	32803	ROSHKA DEWULF & PATTEN PLC
JUL-06	0923	52010	GTP0923		Purchase Invoices USD	$709.90		$709.90	6937776	THELEN REID BROWN RAYSMAN & STEINER LLP
AUG-06	0923	52010	GTP0923		Purchase Invoices USD	$2,589.90		$2,589.90	6940979	THELEN REID BROWN RAYSMAN & STEINER LLP
AUG-06	0923	52010	GTP0923		Purchase Invoices USD	$75.30		$75.30	773853	LEWIS AND ROCA LLP
SEP-06	0923	52010	GTP0923		Purchase Invoices USD	$2,574.37		$2,574.37	6944323	THELEN REID BROWN RAYSMAN & STEINER LLP
OCT-06	0923	52010	GTP0923		Purchase Invoices USD	825.00		825.00	33212	ROSHKA DEWULF & PATTEN PLC
OCT-06	0923	52010	GTP0923		Purchase Invoices USD	282.00		$282.00	32937	ROSHKA DEWULF & PATTEN PLC
NOV-06	0923	52010	GTP0923		Purchase Invoices USD	52.88		$52.88	781384	LEWIS AND ROCA LLP
NOV-06	0923	52010	GTP0923		Purchase Invoices USD	903.10		$903.10	33350	ROSHKA DEWULF & PATTEN PLC
DEC-06	0923	52010	GTP0923		Purchase Invoices USD	85.00		$85.00	33475	ROSHKA DEWULF & PATTEN PLC
DEC-06	0923	52010	GTP0923		Purchase Invoices USD	75.50		$75.50	785015	LEWIS AND ROCA LLP
JAN-06	0923	52010	GTPA160		Purchase Invoices USD	39,128.51		39,128.51	534850	FLEISCHMAN & WALSH LLP
FEB-06	0923	52010	GTPA160		Purchase Invoices USD	29,845.48		29,845.48	535137a	FLEISCHMAN & WALSH LLP
MAR-06	0923	52010	GTPA160		Purchase Invoices USD	29,845.48		29,845.48	535137	FLEISCHMAN & WALSH LLP
MAR-06	0923	52010	GTPA160		Purchase Invoices USD		29,845.48	(29,845.48)	535137a	FLEISCHMAN & WALSH LLP
MAR-06	0923	52010	GTPA160		Purchase Invoices USD	11,595.58		11,595.58	535457	FLEISCHMAN & WALSH LLP
APR-06	0923	52010	GTPA160		Purchase Invoices USD	6,050.00		6,050.00	578939	LOCKE LIDDELL & SAPP LLP
MAY-06	0923	52010	GTPA160		Purchase Invoices USD	30,806.84		30,806.84	584116	LOCKE LIDDELL & SAPP LLP
JUN-06	0923	52010	GTPA160		Purchase Invoices USD	43,278.93		43,278.93	588485	LOCKE LIDDELL & SAPP LLP
JUN-06	0923	52010	GTPA160		Purchase Invoices USD	43,545.07		43,545.07	591248	LOCKE LIDDELL & SAPP LLP
AUG-06	0923	52010	GTPA160		Purchase Invoices USD	38,875.06		38,875.06	596069	LOCKE LIDDELL & SAPP LLP
SEP-06	0923	52010	GTPA160		Purchase Invoices USD	39,214.58		39,214.58	599777	LOCKE LIDDELL & SAPP LLP
SEP-06	0923	52010	GTPA160		Purchase Invoices USD	38,130.60		38,130.60	603092	LOCKE LIDDELL & SAPP LLP
DEC-06	0923	52010	GTPA160		Purchase Invoices USD	38,828.60		38,828.60	611255	LOCKE LIDDELL & SAPP LLP
DEC-06	0923	52010	GTPA160		Purchase Invoices USD	35,947.61		35,947.61	607369	LOCKE LIDDELL & SAPP LLP
JAN-06	0923	52010	GTPD160		Purchase Invoices USD	17,612.56		17,612.56	1205 4752328	ROSHKA DEWULF & PATTEN PLC
FEB-06	0923	52010	GTPD160		Purchase Invoices USD	8,983.00		8,983.00	0106 7052065	ROSHKA DEWULF & PATTEN PLC
APR-06	0923	52010	GTPD160		Purchase Invoices USD	412.50		412.50	0306 8497530	ROSHKA DEWULF & PATTEN PLC
MAY-06	0923	52010	GTPD160		Purchase Invoices USD	508.50		508.50	053106 5737731	ROSHKA DEWULF & PATTEN PLC
OCT-06	0923	52010	GTPD160		Purchase Invoices USD	205.50		205.50	32937	ROSHKA DEWULF & PATTEN PLC
JUN-06	0923	52010	GTPF100		Purchase Invoices USD	1,575.00		1,575.00	050906 40642	BEALE MICHEAELS & SLACK PC
JUL-06	0923	52010	GTPF160		Purchase Invoices USD	267.13		267.13	071806 40642-0010	BEALE MICHEAELS & SLACK PC
JUL-06	0923	52010	GTPF100		Purchase Invoices USD	5,722.41		5,722.41	400420010061200	BEALE MICHEAELS & SLACK PC
SEP-06	0923	52010	GTPF160		Purchase Invoices USD	2,091.35		2,091.35	090606 209135	BEALE MICHEAELS & SLACK PC
OCT-06	0923	52010	GTPF160		Purchase Invoices USD	1,362.50		1,362.50	101106 40642-0010	BEALE MICHEAELS & SLACK PC
OCT-06	0923	52010	GTPF160		Purchase Invoices USD	1,267.24		1,267.24	092506 40642-0010	BEALE MICHEAELS & SLACK PC
NOV-06	0923	52010	GTPF160		Purchase Invoices USD	802.97		802.97	11581	INVESTIGATIVE RESEARCH INC
DEC-06	0923	52010	GTPF160		Purchase Invoices USD	5,838.43		5,838.43	111006 40640-0010	BEALE MICHEAELS & SLACK PC
NOV-06	0923	52010			Accrual USD DEC-06	0.54		0.54		
DEC-06	0923	52010			Accrual USD JAN-07	0.53		0.53		
OCT-06	0923	52010			Accrual USD NOV-06	0.54		0.54		
SEP-06	0923	52010			Accrual USD OCT-06	0.54		0.54		
AUG-06	0923	52010			Accrual USD SEP-06	0.54		0.54		
DEC-06	0923	52010			J341 - Legal Accrual Accrual USD		49,400.00	(49,400.00)		
DEC-06	0923	52000			J341 - Legal Accrual Accrual USD	13,000.00		13,000.00		

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UNS Gas Legal Expenses - 2006

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
JUN-06	0923	52010			J341 Legal Invoice Accrua	43,000.00		43,000.00		
SEP-06	0923	52010			J341 Legal Invoice Accrua	40,000.00		40,000.00		
FEB-06	0923	52010			J342 TEP/UNE/UNG Manual A	41,441.06		41,441.06		
NOV-06	0923	52010			J342 TEP/UNE/UNG Manual A	38,828.60		38,828.60		
DEC-06	0923	52010			J343 - Reverses "J342 TEP/UNE/UNG Manual A Adjustment		38,828.60	(38,828.60)		
MAR-06	0923	52010			J343 - Reverses "J342 TEP/UNE/UNG Manual A Adjustment		41,441.06	(41,441.06)		
JAN-06	0923	52010			J904 - Reverses "Reverses "J1015 Year End Accrual La Adjustment USD"07-FEB-06 08:39:45	17,612.56		17,612.56		
AUG-06	0923	52010			J906 UNS/TEP/UES Credit A		3,299.70	(3,299.70)		
SEP-06	0923	52010			J907 Correct coding of le Tax USD		2,574.37	(2,574.37)		
FEB-06	0923	52010			J909 - Reverses "J962 Jan-06 Inv. With Feb Adjustment USD"08-MAR-		41,062.23	(41,062.23)		
JAN-06	0923	52010			J925 - Reverses "J904 - Reverses "Reverses "J1015 Year End Accrual La Adjustment USD"07"08		17,612.56	(17,612.56)		
JAN-06	0923	52010			J926 Reverses J1015 A/P		17,612.56	(17,612.56)		
JAN-06	0923	52010			J932 - Reverses "J1020 Year End Accrual La Adjustment USD"14-FEB-		39,128.51	(39,128.51)		
DEC-06	0923	52010			J960 Additional TEP/UNG/U	143.90		143.90		
JAN-06	0923	52010			J962 Jan-06 Inv. With Feb	41,062.23		41,062.23		
DEC-06	0923	52010			Reverses "Accrual USD DEC-06"29-DEC-06 11:21:23		0.54	(0.54)		
NOV-06	0923	52010			Reverses "Accrual USD NOV-06"29-NOV-06 14:07:40		0.54	(0.54)		
OCT-06	0923	52010			Reverses "Accrual USD OCT-06"27-OCT-06 09:31:05		0.54	(0.54)		
SEP-06	0923	52010			Reverses "Accrual USD SEP-06"25-SEP-06 15:34:55		0.54	(0.54)		
	Sum					719,347.85	280,807.23	438,540.62		
Total						719,347.85	280,807.23	438,540.62		

Task	Task Description	
GTP0923	Admin & General Salaries	$12,460.02
GTPA160	Legal: El Paso Gas Allocation	$395,246.86
GTPD160	Legal: PGA Application	$27,722.06
GTPF160	Legal: UNSG Santa Cruz Gomez v. Cabrera, et al.	$18,927.03
	All other - JE, Accruals, Reversals	($15,815.35)
		$438,540.62

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UNS Gas Legal Expenses - 2005

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
MAY-05	0902	52010	G550902	OLSEN'S GRAIN		21.70		21.70		
	Sum					21.70		21.70		
MAR-05	0923	52010	G500921	TARGET 00009357		37.83		37.83		
JUL-05	0923	52010	G500921	TINKER & RASOR		$457.79		$457.79		
JAN-05	0923	52010	GTP0923		Purchase Invoices USD	$307.13		$307.13	719109	LEWIS AND ROCA LLP
JAN-05	0923	52010	GTP0923		Purchase Invoices USD	$19,216.41		$19,216.41	722228	LEWIS AND ROCA LLP
JAN-05	0923	52010	GTP0923		Purchase Invoices USD	$200.00		$200.00	200 0105	MARY L BONILLA ENDATED
JAN-05	0923	52010	GTP0923		Purchase Invoices USD	$18.00		$18.00	7740763	ROSHKA DEWULF & PATTEN PLC
JAN-05	0923	52010	GTP0923		Purchase Invoices USD	$600.00		$600.00	10313076	THELEN REID BROWN RAYSMAN & STEINER LLP
MAR-05	0923	52010	GTP0923		Purchase Invoices USD	$563.40		$563.40	5779900	ROSHKA DEWULF & PATTEN PLC
MAR-05	0923	52010	GTP0923		Purchase Invoices USD	$252.00		$252.00	30473	ROSHKA DEWULF & PATTEN PLC
MAR-05	0923	52010	GTP0923		Purchase Invoices USD	89.34		89.34	43056-00001 02/05	LEWIS AND ROCA LLP
APR-05	0923	52010	GTP0923		Purchase Invoices USD	180.00		$180.00	9856239	ROSHKA DEWULF & PATTEN PLC
APR-05	0923	52010	GTP0923		Purchase Invoices USD	111.35		$111.35	730641	LEWIS AND ROCA LLP
MAY-05	0923	52010	GTP0923		Purchase Invoices USD	7,616.25		$7,616.25	6884398	THELEN REID BROWN RAYSMAN & STEINER LLP
JUN-05	0923	52010	GTP0923		Purchase Invoices USD	13,411.45		$13,411.45	6887902	THELEN REID BROWN RAYSMAN & STEINER LLP
JUN-05	0923	52010	GTP0923		Purchase Invoices USD	133.75		$133.75	43056-00001 05/05	LEWIS AND ROCA LLP
JUL-05	0923	52010	GTP0923		Purchase Invoices USD	216.00		216.00	6835245 06/05	ROSHKA DEWULF & PATTEN PLC
JUL-05	0923	52010	GTP0923		Purchase Invoices USD	3.75		3.75	6895440	THELEN REID BROWN RAYSMAN & STEINER LLP
SEP-05	0923	52010	GTP0923		Purchase Invoices USD	40.80		40.80	1092930 081505	LEWIS AND ROCA LLP
OCT-05	0923	52010	GTP0923		Purchase Invoices USD	297.80		297.80	12079283 0805	ROSHKA DEWULF & PATTEN PLC
OCT-05	0923	52010	GTP0923		Purchase Invoices USD	1,928.24		1,928.24	10178709 100105	ROSHKA DEWULF & PATTEN PLC
OCT-05	0923	52010	GTP0923		Purchase Invoices USD	313.61		313.61	694353 100105	LEWIS AND ROCA LLP
NOV-05	0923	52010	GTP0923		Purchase Invoices USD	396.00		396.00	1005 11237055	ROSHKA DEWULF & PATTEN PLC
DEC-05	0923	52010	GTP0923		Purchase Invoices USD	139.20		139.20	1005 78240	LEWIS AND ROCA LLP
DEC-05	0923	52010	GTP0923		Purchase Invoices USD	1,662.40		1,662.40	1105 5888581	ROSHKA DEWULF & PATTEN PLC
FEB-05	0923	52010	GTP0923				18,866.48	(18,866.48)		
JAN-05	0923	52010	GTPA160		Purchase Invoices USD	6,248.77		6,248.77	531564	FLEISCHMAN & WALSH LLP
MAR-05	0923	52010	GTPA160		Purchase Invoices USD	19,887.55		19,887.55	532093	FLEISCHMAN & WALSH LLP
APR-05	0923	52010	GTPA160		Purchase Invoices USD	19,482.02		19,482.02	532341	FLEISCHMAN & WALSH LLP
APR-05	0923	52010	GTPA160		Purchase Invoices USD	19,083.78		19,083.78	531797	FLEISCHMAN & WALSH LLP
MAY-05	0923	52010	GTPA160		Purchase Invoices USD	87,268.56		87,268.56	532735	FLEISCHMAN & WALSH LLP
JUN-05	0923	52010	GTPA160		Purchase Invoices USD		720.00	(720.00)	351816	THELEN REID BROWN RAYSMAN & STEINER LLP
JUN-05	0923	52010	GTPA160		Purchase Invoices USD	11,030.00		11,030.00	532812	FLEISCHMAN & WALSH LLP
JUL-05	0923	52010	GTPA160		Purchase Invoices USD	14,299.22		14,299.22	533248	FLEISCHMAN & WALSH LLP
AUG-05	0923	52010	GTPA160		Purchase Invoices USD	28,463.40		28,463.40	533381	FLEISCHMAN & WALSH LLP
SEP-05	0923	52010	GTPA160		Purchase Invoices USD	56,611.88		56,611.88	533691	FLEISCHMAN & WALSH LLP
OCT-05	0923	52010	GTPA160		Purchase Invoices USD	32,330.68		32,330.68	3233068 0805	FLEISCHMAN & WALSH LLP
NOV-05	0923	52010	GTPA160		Purchase Invoices USD	28,712.29		28,712.29	534292	FLEISCHMAN & WALSH LLP
DEC-05	0923	52010	GTPA160		Purchase Invoices USD	38,534.74		38,534.74	534589	FLEISCHMAN & WALSH LLP
MAR-05	0923	52010	GTPD160		Purchase Invoices USD	386.00		386.00	30473	ROSHKA DEWULF & PATTEN PLC
APR-05	0923	52010	GTPD160		Purchase Invoices USD	11,201.01		11,201.01	9856239	ROSHKA DEWULF & PATTEN PLC
JUN-05	0923	52010	GTPD160		Purchase Invoices USD	11,234.83		11,234.83	MAY-05	ROSHKA DEWULF & PATTEN PLC
JUN-05	0923	52010	GTPD160		Purchase Invoices USD	2,490.20		2,490.20	233 05/05	ROSHKA DEWULF & PATTEN PLC
JUL-05	0923	52010	GTPD160		Purchase Invoices USD	360.00		360.00	6835245 06/05	ROSHKA DEWULF & PATTEN PLC
OCT-05	0923	52010	GTPD160		Purchase Invoices USD	2,304.50		2,304.50	12079283 0805	ROSHKA DEWULF & PATTEN PLC
OCT-05	0923	52010	GTPD160		Purchase Invoices USD	3,411.86		3,411.86	10178709 100105	ROSHKA DEWULF & PATTEN PLC
NOV-05	0923	52010	GTPD160		Purchase Invoices USD	15,277.45		15,277.45	1005 11237055	ROSHKA DEWULF & PATTEN PLC
DEC-05	0923	52010	GTPD160		Purchase Invoices USD	22,236.08		22,236.08	1105 5888581	ROSHKA DEWULF & PATTEN PLC
OCT-05	0923	52010	GTPF160		Purchase Invoices USD	462.00		462.00	6594	BOULEY & SCHIPPERS
DEC-05	0923	52010	GTPF160		Purchase Invoices USD	228.00		228.00	6728	BOULEY & SCHIPPERS

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UNSG0571/02573

UNS Gas Legal Expenses - 2005

Company:032
Expenditure Type:152
BY FERC

GL Period	FERC	Acct	Pa Task Number	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Invoice Number	Vendor Name
DEC-05	0923	52010			J1015 Year End Accrual La Adjustment USD	17,612.56		17,612.56		
DEC-05	0923	52010			J1020 Year End Accrual La Adjustment USD	39,128.51		39,128.51		
APR-05	0923	52010			J342 TEP/UNE/UNG Manual A Adjustment USD	87,268.56		87,268.56		
APR-05	0923	52010			J901 - Reverses "J930 TEP/UNE/UNG Manual A Adjustment USD"28-APR-05 09:19:07		111.00	(111.00)		
MAY-05	0923	52010			J902 - Reverses "J342 TEP/UNE/UNG Manual A Adjustment USD"31-MAY-05 11:06:06		87,268.56	(87,268.56)		
MAY-05	0923	52010			J905 Capitalize Debt-rela Adjustment USD		7,616.25	(7,616.25)		
MAY-05	0923	52010			J906 Reverse Dec 2004 J34 Adjustment USD		349.93	(349.93)		
JUN-05	0923	52010			J908 - Correct Recording Tax USD		13,411.45	(13,411.45)		
JAN-05	0923	52010			J909 - Reverses "J933 TEP/UNE/UNG Manual A Adjustment USD"03-FEB-05 16:33:57		246,924.07	(246,924.07)		
JAN-05	0923	52010			J922 UNSE/UNSG Correction Adjustment USD	239,768.17		239,768.17		
MAR-05	0923	52010			J930 TEP/UNE/UNG Manual A Adjustment USD	111.00		111.00		
	Sum					863,626.12	375,267.74	488,358.38		
Total						863,647.82	375,267.74	488,380.08		

Task	Task Description	
GTP0923	Admin & General Salaries	$28,830.40 A
GTPA160	Legal: El Paso Gas Allocation	$361,232.89
GTPD160	Legal: PGA Application	$68,901.93
GTPF160	Legal: UNSG Santa Cruz Gomez v. Cabrera, et al.	$690.00
	All other - JE, Accruals, Reversals	$28,724.86
		$488,380.08

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UNSG0571/02574

5.2

UNS Gas, Inc.
Payroll Adjustment
Test Year Ended June 30, 2008

FERC Account	TY 06/2008 Regular Wages Per Books	% Of TY 06/2008 Regular Wages	TY 06/2008 Overtime	% Of TY 06/2008 Overtime Wages	TY 06/2008 Allocated From CLR Accts	% Of TY 06/2008 Allocated From CLR Accts	(A) Total Wages Recorded by UNSG in CLR Accts	Regular Annualized Payroll As of July 2008	2009 & 2010 Wage Increase	Adjusted Overtime	Estimate Allocated From CLR Accts	(B) Total Adjusted Payroll With Overtime	A (B-A) Payroll Adjustment
	Data for the Test Year Ending June 30, 2008							Adjusted Payroll - Annualized and Increased for 2009 & 2010 wage increase					
Classified													
Operations - Gas													
Transmission													
0870 Trans-Oper Supervision & Engr	3A 72.95	0.00%	6A 21,166.22	3.11%	9.66	0.00%	21,248.83	71.08	75.41	24,743.12	10.01	24,828.53	3,580
Distribution													
0874 Dist-Mains & Services Exp 5b	430,747.35	4.46%	61,918.49	7.63%	57,013.18	7.38%	539,679.02	419,685.56	445,244.44	60,692.24	59,107.16	565,043.83	25,365
0875 Dist-Meas & Reg Station Exp-Gen	15,511.75	0.16%	546.06	0.08%	2,083.12	0.27%	18,109.93	15,113.40	16,033.81	637.17	2,128.52	18,799.50	690
0876 Dist-Meas & Reg Station Exp-Ind	0.00	0.00%	118.74	0.02%	-	0.00%	118.74	-	-	138.81	-	138.81	20
0877 Dist-Meas & Reg Station Exp-CtGt	13,453.52	0.14%	748.43	0.11%	1,760.89	0.23%	15,982.64	13,106.03	13,906.31	874.91	1,846.09	16,627.31	645
0878 Dist-Meter Exp 5b +	780,846.87	8.08%	163,457.09	24.02%	103,351.92	13.37%	1,047,655.88	760,794.41	807,126.78	191,079.83	107,147.83	1,105,354.44	57,699
0879 Dist-Customer Installations Exp +	373,188.44	3.86%	205,601.35	30.21%	49,394.76	6.39%	628,184.55	363,604.81	385,748.34	240,348.08	51,208.93	677,303.35	49,119
0880 Dist-Other Expenses +	174,638.41	1.81%	14,675.62	2.16%	23,114.92	2.99%	212,428.95	170,153.62	180,515.98	17,165.66	23,963.69	221,635.53	9,207
Customer Accounting													
0902 Meter Reading Expense +	428,519.93	4.43%	73,136.08	10.75%	56,718.37	7.34%	558,376.38	417,515.36	442,942.05	85,497.74	58,801.51	587,241.30	28,865
0903 Cust Rec/Collection Exp 5.1e +	486,654.27	5.04%	53,671.99	7.89%	64,439.43	8.34%	604,965.69	474,351.65	503,239.67	62,742.06	66,806.15	632,787.88	27,822
0905 Misc Customer Accts Exp	238.29	0.00%	-	0.00%	31.54	0.00%	269.83	232.17	246.31	-	32.70	279.01	9
Customer Service & Information													
0908 Customer Assistance Exp	13,796.80	0.14%	-	0.00%	1,826.13	0.24%	15,622.93	13,442.49	14,261.14	-	1,893.20	16,154.34	531
Administration & General													
0920 A&G Salaries	18,737.01	0.19%	181.10	0.03%	2,480.01	0.32%	21,398.12	18,255.84	19,367.62	211.70	2,571.09	22,150.41	752
0925 Injuries & Damages	25,599.10	0.26%	-	0.00%	3,388.27	0.44%	28,987.37	24,941.70	26,460.85	-	3,512.71	29,973.36	986
0926 Pensions & Benefits	227.50	0.00%	18,362.50	2.70%	30.11	0.00%	18,620.11	221.66	235.16	21,466.59	31.22	21,731.97	3,112
0930 General Advertising Exp	793.04	0.01%	174.81	0.03%	104.97	0.01%	1,072.82	772.67	819.73	204.35	108.82	1,132.90	60
Total Operations	2,783,225.23	28.60%	603,759.48	88.71%	365,737.06	47.33%	3,732,721.77	2,692,264.48	2,856,223.39	705,789.26	379,169.83	3,941,182.46	208,461
Maintenance - Gas													
Distribution													
0885 Dist-Maint Supervision & Engr	0.00	0.00%	-	0.00%	-	0.00%	-	-	-	-	-	-	0
0887 Dist-Maint of Mains 5b +	140,871.14	1.46%	41,494.77	6.10%	18,645.53	2.41%	201,011.44	137,253.51	145,612.25	48,507.00	19,330.34	213,449.59	12,438
0889 Dist-Maint Meas & Reg Station Equip-Gen	5,000.64	0.05%	1,084.97	0.16%	661.88	0.09%	6,747.49	4,872.22	5,166.94	1,268.32	686.19	7,123.46	376
0890 Dist-Maint Meas & Reg Station Equip-Ind	0.00	0.00%	-	0.00%	-	0.00%	-	-	-	-	-	-	0
0891 Dist-Maint Meas & Reg Station Exp-CtGt	522.28	0.01%	110.76	0.02%	69.13	0.01%	702.17	508.87	539.86	129.48	71.67	741.00	39
0892 Dist-Maint of Services 5b +	129,704.07	1.34%	30,441.13	4.47%	17,167.47	2.22%	177,312.67	126,373.22	134,069.35	35,585.40	17,798.00	187,452.74	10,140
0893 Dist-Maint of Meters 5b +	74,871.22	0.77%	3,271.65	0.48%	9,909.86	1.26%	88,052.73	72,946.50	77,391.08	3,824.53	10,273.83	91,489.42	3,437
0894 Dist-Maint of Other Equipment	2,235.94	0.02%	419.00	0.06%	295.95	0.04%	2,950.89	2,178.52	2,311.19	489.81	306.82	3,107.81	157
Administrative & General													
0932 Dist-Maint of General Plant	5,837.07	0.06%	31.83	0.00%	772.59	0.10%	6,641.49	5,687.17	6,033.52	37.21	800.98	6,871.69	230
Total Maintenance	359,042.36	3.72%	76,854.11	11.29%	47,522.40	6.15%	483,418.87	349,822.01	371,126.17	89,841.74	49,287.80	510,235.71	26,817
Total Operations & Maintenance - CLS	3,122,267.59 = 3B	32.31%	680,613.59	1.00	413,259.47 13a	53.48%	4,216,140.65	3,042,086.49	3,227,349.56	$795,631.00 2A	428,437.63	4,451,418.19	235,278
Unclassified													
Operations - Gas													
Transmission													
0856 Trans-Mains Exp	4A 7,755.85	0.08%	7A 730.28	0.76%	1,026.55	0.13%	9,512.68	7,556.68	8,016.86	897.68	1,064.26	9,978.82	466
0857 Trans-Meas & Reg Station Exp	0.00	0.00%	-	0.00%	-	0.00%	-	-	-	-	-	-	0
0870 Trans-Oper Supervision & Engr 5.1f +	193,118.12	2.00%	-	0.00%	25,560.87	3.31%	218,678.99	188,156.77	199,617.64	-	26,499.67	226,117.31	7,438
Distribution													
0874 Dist-Mains & Services Exp	411,826.06	4.26%	11,626.74	12.05%	54,508.79	7.05%	477,961.59	401,250.20	425,686.34	14,291.92	56,510.78	496,489.04	18,527
0875 Dist-Meas & Reg Station Exp-Gen 5.1f +	105,108.91	1.09%	1,996.81	2.07%	13,912.08	1.80%	121,017.80	102,409.67	108,646.42	2,454.54	14,423.05	125,524.00	4,506
0876 Dist-Meas & Reg Station Exp-Ind	110,461.57	1.14%	2,652.76	2.75%	14,620.56	1.89%	127,734.89	107,624.87	114,179.23	3,260.85	15,157.54	132,597.61	4,863
0877 Dist-Meas & Reg Station Exp-CtGt	3,955.85	0.04%	273.71	0.28%	523.59	0.07%	4,753.15	3,854.26	4,088.99	336.45	542.82	4,968.26	215
0878 Dist-Meter Exp	1,606.88	0.02%	-	0.00%	212.68	0.03%	1,819.56	1,565.61	1,660.96	-	220.50	1,881.46	62
0879 Dist-Customer Installations Exp 5.1f +	7,666.82	0.08%	771.21	0.80%	1,014.77	0.13%	9,452.80	7,469.93	7,924.85	947.99	1,052.04	9,924.69	472
0880 Dist-Other Expenses	195,919.44	2.03%	2,001.49	2.07%	25,931.65	3.36%	223,852.58	190,888.15	202,513.24	2,460.29	26,664.07	231,857.60	8,005
Customer Accounting													
0901 Cust Accounting-Supervision	3,270.50	0.03%	-	0.00%	432.88	0.06%	3,703.38	3,186.51	3,380.57	-	448.78	3,829.35	126
0902 Meter Reading Expense	74,573.45	0.77%	18,032.59	18.69%	9,870.45	1.28%	102,476.49	72,658.37	77,083.27	22,166.18	10,232.97	109,482.41	7,006
0903 Cust Rec/Collection Exp + 905 - Misc. Cust. Accts	107,755.69	1.12%	-	0.00%	14,262.41	1.85%	122,018.10	104,988.48	111,382.28	-	14,786.24	126,168.52	4,150

UNSG0571/02585

UNS Gas, Inc.
Payroll Adjustment
Test Year Ended June 30, 2008

FERC Account	TY 06/2008 Regular Wages Per Books	% Of TY 06/2008 Regular Wages	TY 06/2008 Overtime	% Of TY 06/2008 Overtime Wages	TY 06/2008 Allocated From CLR Accts	% Of TY 06/2008 Allocated From CLR Accts	(A) Total Wages Recorded by UNSG in CLR Accts	Regular Annualized Payroll As of July 2008	2009 & 2010 Wage Increase	Adjusted Overtime	Estimate Allocated From CLR Accts	(B) Total Adjusted Payroll With Overtime	(B-A) Payroll Adjustment
	Data for the Test Year Ending June 30, 2008							Adjusted Payroll - Annualized and Increased for 2009 & 2010 wage increase					
Customer Service & Information													
0908 Customer Assistance Exp	4A 1,805.54	0.02%	7A -	0.00%	238.98	0.03%	2,044.52	1,759.17	1,866.31	-	247.76	2,114.06	70
0910 Misc Cust Service/Info Exp	0.00	0.00%	-	0.00%	-	0.00%	-	-	-	-	-	-	0
Administration & General													
0920 A&G Salaries	5.1f+5.2f 982,694.93	10.17%	1,881.10	1.95%	130,068.28	16.83%	1,114,644.31	957,458.93	1,015,768.17	2,312.30	134,845.42	1,152,925.90	38,282
0925 Injuries and Damages	7,720.57	0.08%	-	0.00%	1,021.89	0.13%	8,742.46	7,522.30	7,980.41	-	1,059.42	9,039.83	297
0930 General Advertising Exp	241.54	0.00%	-	0.00%	31.97	0.00%	273.51	235.34	249.67	-	33.14	282.81	9
Total Operations	2,215,461.72	22.93%	39,966.69	41.42%	293,238.41	37.95%	2,548,686.82	2,158,587.25	2,290,045.21	49,126.20	304,008.45	2,643,181.86	94,495
Maintenance - Gas													
Production													
0554 Maint of Misc Oth Pwr Gen Plant	0.00	0.00%	-	0.00%	-	0.00%	-	-	-	-	-	-	0
Distribution													
0886 Dist-Maint Supervision & Engr	5.1f 151,848.12	1.57%	-	0.00%	20,098.43	2.60%	171,946.55	147,946.60	156,958.67	-	20,836.60	177,795.27	5,849
0887 Dist-Maint of Mains	191,890.46	1.99%	31,929.70	33.09%	25,398.38	3.29%	249,218.54	186,962.64	198,348.66	39,246.90	26,331.21	263,926.77	14,710
0889 Dist-Maint Meas & Reg Station Equip-Gen	4,125.38	0.04%	387.24	0.40%	546.03	0.07%	5,058.65	4,019.44	4,264.22	476.01	566.08	5,306.31	246
0891 Dist-Maint Meas & Reg Station Exp-CtGt	1,023.98	0.01%	203.32	0.21%	135.53	0.02%	1,362.83	997.68	1,058.44	249.93	140.51	1,448.88	88
0892 Dist-Maint of Services	138,446.66	1.43%	23,600.44	24.46%	18,324.63	2.37%	180,371.73	134,891.29	143,106.17	29,010.34	18,997.65	191,114.16	10,742
0893 Dist-Maint of Meters	7,443.18	0.08%	408.90	0.42%	985.17	0.13%	8,837.25	7,252.04	7,693.69	502.63	1,021.35	9,217.67	380
0894 Dist-Maint of Other Equipment	1,259.60	0.01%	-	0.00%	166.72	0.02%	1,426.32	1,227.25	1,301.99	-	172.84	1,474.84	49
Administrative & General													
0932 Dist-Maint of General Plant	4,713.69	0.05%	-	0.00%	623.92	0.08%	5,337.81	4,592.84	4,872.54	-	646.84	5,519.38	182
Total Maintenance	500,751.27	5.18%	56,529.60	58.58%	66,278.82	8.58%	623,559.69	487,891.77	517,604.38	69,487.80	68,713.10	655,805.29	32,249
Total Operations & Maintenance - UNC	2,716,232.99 4B	28.11%	96,496.29	100.00%	359,517.23 13b	46.52%	3,172,246.51	2,646,479.02	2,807,649.60	$118,616.00 2B	372,721.55	3,298,987.15	126,741
Total O&M Wages	(A) 5,838,500.58	60.42%	777,109.88 6B		772,776.70 13a	100.00%	7,388,387.16	5,688,565.51	6,034,999.15 (B)	914,247.00 2c	801,159.18	(2) 7,750,405.34	362,018
Wages Charged to Other Accounts	(C) 3,824,744.05 5.2D	39.58%	243,570.51 6C		(772,776.70) 13c	-100.00%	3,295,537.86	3,726,523.07	3,953,468.32 (D)	264,267.00 2d	(801,159.18)	(1) 3,416,576.14	
Total Payroll	9,663,244.63 (1) =3c	100.00%	1,020,680.39 (1) 6D		- (2)	0.00%	10,683,925.02 8A	9,415,068.58 (3)	9,988,467.48	1,178,514.00 (4)	- (5)	(3) 11,166,981.48	

0.063682826

3% - 2009 Rate Increase	1.03
	9,697,541.24
3% - 2010 Rate Increase	1.03
(6)	9,988,467.48

14a

①/③ = 30.59% to Capital
②/③ = 69.41% to O&M

Notes:
(1) Ties to Classified and Unclassified Distribution based on system generated Payroll by Function Reports
(2) Based on Clearing Account Allocation
(3) Represents UNSG's regular payroll as of July 2008 obtained from Payroll - Total spread to Classified/Unclassified/Wages charged to other account based on % of TY 06/08 regular wages.
(4) The overtime rate represents a 2-year average (TME 6-2007 & 6-2008) increased for the 2009 & 2010 wage rate increase.
Total spread based on % of TY 06/08 overtime by Classified/Unclassified/Non-O&M.
(5) Based on percentage of Total Wages Charged to Other Accounts and then allocated to O&M in Test Year.
(6) Annualized Payroll adjusted for a 3% wage increase in 2008 & 2009

1.1

UNSG0571/02586

UNS Gas, Inc.
Payroll Tax Adjustment
Pro Forma Payroll Taxes
Test Year Ended June 30, 2008

Social Security Tax:

(a) Medicare -		
UNSG Estimated 2009/2010 Payroll - including OT	$11,166,981 4.1a ✓	
Medicare Tax Base	$11,166,981 4.1a ✓	
Medicare Tax Rate (%)	1.45 8b ✓	
Pro Forma Medicare Tax		$161,921 ✓ a
(b) OASDI -		
UNSG Regular Annualized Payroll - Including OT	$11,166,981 4.1a ✓	
Less: Wages in Excess of $102,000 ✓ - 8a - UNSG Unclassified	(99,577.18) 7.2a ✓	
OASDI Tax Base	$11,067,404 ✓	
OASDI Tax Rate (%)	6.20 8a ✓	
Pro Forma OASDI Tax		$686,179 ✓

Federal/State Unemployment Tax:

Number of Employees -		
UNSG Classified	7.1a 118 ✓	
UNSG Unclassified	7.2b 86 ✓	
Total Employees	204 ✓	
Taxable Wages ($)	8.1a 7,000 ✓	
Tax Base	1,428,000 ✓	
Tax Rate (%)	2.80 8c ✓	
Pro Forma FUI/SUI		$39,984 ✓
Total Pro Forma Payroll Taxes		$888,084 F

✓

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Attachment RCS-6
Copies of Confidential UNS Gas' Responses to Data Requests and Workpapers Referenced in the Direct Testimony and Schedules of Ralph C. Smith

****UNS Gas Confidential Pages Have Been Redacted****

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
RUCO 1.46	Amounts of incentive compensation expense included in the test year	Yes	5	2-6
Attachment TF 6.46	UES Results of Operations - Year end 2008	Yes	2	7-8
Attachment TF 6.92	Incentive compensation programs (2008 long-term program term sheet)	Yes	2	9-10
	Total Pages Including this Page		10	

PAGES 2-10 ARE CONFIDENTIAL AND HAVE BEEN REDACTED

Moody's Investors Service

Global Credit Research
Credit Opinion
23 JUL 2009

Credit Opinion: UNS Gas, Inc.

UNS Gas, Inc.

Tucson, Arizona, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Bkd Senior Unsecured	Baa3
Ult Parent: UniSource Energy Corporation	
Outlook	Stable
Sr Sec Bank Credit Facility	Ba1

Contacts

Analyst	Phone
Laura Schumacher/New York	212.553.3853
William L. Hess/New York	212.553.3837

Opinion

Rating Drivers

Stable regulated operations with in historically challenging regulatory environment

Limited non-regulated exposure and ring-fencing

Strong credit metrics

Cross-support within UES family

Corporate Profile

UNS Gas, Inc. (UNSE: Baa3 senior unsecured (guaranteed), stable) is local distribution utility serving approximately 146,000 retail customers in Arizona. UNSG and UNS Electric, Inc. (UNSE: Baa3 senior unsecured (guaranteed), stable), a regulated electric utility in Arizona, are both subsidiaries of UniSource Energy Services (UES) which is the guarantor. UES is a wholly owned subsidiary of UniSource Energy Corporation (UNS: Ba1 senior secured bank credit facility (security limited to stock of certain subsidiaries), stable), whose largest subsidiary is Tucson Electric Power (TEP: Baa3 senior unsecured, stable), a regulated electric utility in Arizona.

SUMMARY RATING RATIONALE

The Baa3 rating assigned to UNSG's senior unsecured notes reflects the interdependence that currently exists between the company and its affiliate UNSE as a result of their shared credit facility and parental guarantee from UES. The rating reflects our view of the consolidated credit quality of UES, which guarantees the debt of both UNSG and UNSE. On a stand-alone basis, UNSG has a credit profile moderately better than its rating as evidenced by metrics that map to rating levels within the LDC gas utility methodology that are somewhat stronger than its rating category.

DETAILED RATING CONSIDERATIONS

Regulated operations in historically challenging environment

Virtually all of UNSG's operations are regulated. Moody's generally views a significant percentage of regulated operations as positive for credit quality as regulated cash flows tend to be more stable and predictable than those of unregulated companies. This key factor is tempered somewhat by the regulatory environment of Arizona, which Moody's generally ranks below average for U.S. regulatory jurisdictions in terms of expectation of timely recovery of costs and predictability of rate decisions. Moody's also notes that three new commissioners began their term in January 2009 and it is not clear how or whether this might impact Moody's perception of the regulatory environment in Arizona over time.

Regulatory lag continues although moderating capital expenditures are a mitigant

UNSG's last fully litigated rate case was resolved in approximately 16 months with new rates in place reflecting a historic test year that ended two years before the decision. This level of regulatory lag makes adequate and timely recovery difficult to achieve. UNS Gas filed a general rate case in November 2008 requesting a $10 million rate increase (6%) premised on an 11% ROE and 50% equity ratio using a June 2008 test year end. A decision is expected by late 2009 or early 2010. Moody's expects further need for rate cases over the medium-term due to regulatory lag and on-going capital expenditures. The utility is not expected to earn its 10% allowed ROE during this time unless it receives adequate rate relief.

Capital expenditures were above $22 million annually from 2005-2007 but are expected to generally remain below $20 million over the near-term. Moderating capital expenditures reduces the need for regulatory relief though lag is expected to continue.

Effective recovery of purchased gas costs

UNSG has a gas cost recovery mechanism that appears to be functioning adequately. The Purchased Gas Adjustor mechanism may be changed monthly based on a comparison of rolling twelve-month average actual gas cost and gas costs in base rates, though there are limits to the levels of adjustments over a twelve month period. UNSG may also request a surcharge to recover deferred balances. As of March 31, 2009, UNSG had a $6 million over recovered purchased gas costs balance included as a current liability.

Due to the traditionally challenging regulatory environment in Arizona, as well as the uncertainty surrounding the impact of new commissioners, the regulatory supportiveness factor has been scored in the Ba range in the LDC methodology framework.

Non-regulated exposure and ring-fencing within UES is limited

Although UNSG's risk of exposure to non-regulated activities is considered quite modest as both UNSG and UNSE are fully regulated, there is significant interdependence between the UES subsidiaries in the form of a shared credit agreement and parental guarantee. Services are also shared with UniSource's primary regulated utility TEP. UNSG contributed approximately 63% of consolidated UES' EBIT and 14% of consolidated UNS' EBIT.

The Arizona Corporation Commission (ACC) has not restricted UNSG's ability to pay dividends to its parent; however, the utility has not paid a dividend over the last several years. There are dividend restrictions under the company's notes and credit agreement, but UNSG is well within the limits imposed by these documents. Overall, ring-fencing at UNSG maps within the Baa criteria outlined in the LDC Methodology.

Cross support of debt within UES constrains rating

The rating also recognizes the position of UNSE and UNSG as indirect subsidiaries of UNS through UES. UES is an intermediate holding company with no operations or debt. Debt at UNSE and UNSG is guaranteed by UES, which creates cross-support. UES has not historically received any dividend payments from its utility subsidiaries, and none are anticipated for the foreseeable future. UNS has periodically contributed equity to UNSG in support of its capital program and to strengthen its balance sheet.

Improved metrics provide credit support for weaker regulatory environment

Credit metrics overall reflect on-going regulatory lag issues as well as the benefits of cost controls, and a modest debt profile.

ROE, EBIT/Customer and EBIT/Interest

UNSG's average ROE, EBIT/Customer and EBIT/Interest have historically mapped to the lower Baa/high Ba level. In 2008, metrics improved moderately due to the impact of the base rate increase in late 2007 and slowing customer growth; however, they continue to map to the high Ba/low Baa level. UNSG's metrics could improve moderately within the Baa rating range if regulatory lag is reduced or the company receives better than anticipated rate relief.

RCF/Debt, Debt to Capitalization and FCF/FFO

UNSG's cash flow and debt-related credit metrics have historically mapped to the upper Baa/low A level. Retained and free cash flow have improved as UNSG has not paid dividends to its parent recently and capital expenditures have begun to decline. This has allowed retained earnings to increase equity capitalization and also reduce the need for new debt financing. Continued moderating levels of capital expenditures are expected to increase free cash flow and debt financing is expected to be minimal over the near-term. Beyond 2010, free cash flow is expected to once again become negative unless rate relief is better than anticipated. Over time, these metrics could improve to the low A range.

Liquidity Profile

UNSG's cash flow profile has generally been stable with operating cash flow approximately covering capital expenditures; however, in 2008, cash from operations of $2.8 million were significantly below capital expenditures of approximately $16 million. Cash on hand was used to meet the shortfall as cash flow was significantly impacted by collateral postings and refunds from over-recovered purchased gas costs. Over the near-term, capital expenditures of $19-21 million annually are expected to continue to be funded roughly by cash flow from operations.

UNSG has two $50 million issues of senior unsecured notes outstanding, one maturing in August 2011 and one maturing in 2015. UNSG's short term liquidity needs are supported by a joint UNSG/UNSE $60 million credit facility which matures August 2011. Either borrower may borrow up to a maximum of $45 million, so long as the combined amount does not exceed $60 million. As of March 31, 2009, there were no amounts drawn on the facility but UNSE had $17 million of letters of credit outstanding and UNSG had $5 million of letters of credit outstanding which reduced availability under the facility.

The UNSG/UNSE credit facility contains two financial covenants applicable to each borrower: for UNSE a maximum debt to capital ratio of 65% and a minimum interest coverage ratio of 2.25 times, for UNSG a maximum debt to capital ratio of 67%, and a minimum interest coverage of 2.25 times. As of March 31, 2009, the ratios were 54% and 4.01 times at UNSE and 50% and 4.02 times at UNSG. The credit facility requires a material adverse change (MAC) representation at each new borrowing. In Moody's opinion, the requirement of a MAC representation significantly increases the risk that the credit facility may not be available when liquidity needs are greatest.

Moody's assumes that UNSG will manage the amount of its near term obligations within the limits of its available sources of cash, including its committed bank credit facilities.

Rating Outlook

The stable outlook for UNSG reflects our expectations of continued stable or modestly improved cash flows resulting from expected rate case decisions, an assumption that any increases in the cost of gas will continue to be recovered on a relatively timely basis, and our understanding that future capital expenditures will be financed in a manner intended to maintain UNSG's current level of financial strength and flexibility.

What Could Change the Rating - Up

UNSG's rating is currently constrained by its interdependence with UNSE and our view of the consolidated credit quality of UES. In the event this interdependence was reduced while UNSG retained its similar credit profile, the rating or outlook could be revised upward. Alternatively, if there were to be an improvement in the consolidated credit quality of UES, this could result in positive rating action for UNSG.

What Could Change the Rating - Down

A downward revision could occur if there is deterioration in the credit quality or ratings of UES or UNSE or UNSG credit metrics decline to the low Baa/high Ba range, for example, RCF/Debt below 10% or EBIT / Interest coverage of less than 2x, or if regulatory support significantly worsens, then there could be a downward revision in the rating or outlook.

Rating Factors

UNS Gas, Inc.

Local Gas Distribution	Aaa	Aa	A	Baa	Ba	B	Caa
Factor 1: Sustainable Profitability (20%)							

a) Return on Equity (15%)				X			
b) EBIT to Customer Base (5%)				X			
Factor 2: Regulatory Support (10%)							
a) Regulatory Support and Relationship					X		
Factor 3: Ring Fencing (10%)							
a) Ring Fencing				X			
Factor 4: Financial Strength and Flexibility (60%)							
a) EBIT/Interest (15%)				X			
b) Retained Cash Flow/Debt (15%)			X				
c) Debt to Book Capitalization (excluding goodwill) (15%)				X			
d) Free Cash Flow/Funds from Operations (15%)			X				
Rating:							
a) Methodology Model Implied Senior Unsecured Rating				**Baa2**			
b) Actual Senior Unsecured Equivalent Rating				**Baa3**			

EXHIBIT
R-21
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-04204A-08-0571

NON-CONFIDENTIAL SURREBUTTAL

TESTIMONY

[**CONFIDENTIAL INFORMATION HAS BEEN REDACTED**]

OF

RALPH C. SMITH

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 29, 2009

TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-08-0571
SURREBUTTAL TESTIMONY OF RUCO WITNESS RALPH C. SMITH

My testimony addresses the following issues, and responds to the rebuttal testimony of UNS Gas, Inc. ("UNSG", "UNS Gas," or "Company") witnesses on these issues:

- The Company's proposed revenue requirement
- The determination of a Fair Value Rate of Return and its application to Fair Value Rate Base
- RUCO's recommended base revenue increase
- Adjusted Rate base
- Adjusted Test year revenues, expenses, and net operating income

My findings and recommendations for each of these areas are as follows:

The Company's Proposed Revenue Requirement
The Company had originally proposed a revenue requirement of a base rate increase of $9.480 million, or 18.53 percent. In its rebuttal, UNSG calculated a base rate increase that is approximately $146,000 higher than its original request, but indicated that it is not requesting a revenue requirement higher than proposed in its original Application. The Company's requested rate increase is significantly overstated.

UNSG overstated rate base and understated operating income. Additionally, the Company is requesting an excessive rate of return. The direct and rebuttal testimony of RUCO witness William Rigsby addresses RUCO's recommended return on equity and weighted cost of capital to be applied to OCRB.

The Determination of a Fair Value Rate of Return (FVROR) and its Application to FVRB
The Commission's traditional calculation of return on fair value rate base calculation has been called into question by a recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income in that case had ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

That Court of Appeals decision provided some guidance for calculating the return on fair value rate base. For example, at pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision stated that: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

The Commission reopened Docket No. W-02113A-04-0616 to address such issues in a Chaparral City remand proceeding and, on July 28, 2008, issued Decision No. 70441. In Decision No. 70441, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the Commission can use to determine an appropriate FVROR, including adjusting the weighted average cost of capital ("WACC") to exclude the effect of inflation on the cost of equity, and that the FVROR adopted there fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process.

Attachment RCS-2, Schedule D, page 2, to my direct testimony showed the derivation of four FVROR calculations that were considered by RUCO, including:

- Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation
- Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation
- Calculation 3 - With Fair Value Rate Base Increment at Zero Cost
- Calculation 4 - With Fair Value Rate Base Increment at 1.25 Percent

My surrebuttal testimony in the instant rate case elaborates upon RUCO's derivation of the fair value return on fair value rate base calculations in view of the Court of Appeals decision concerning Chaparral and the Commission's Decision No. 70441 in the Chaparral remand case, as described above.

Adjusted Rate Base
The following adjustments to UNSG's proposed original cost rate base should be made:

- UNSG's proposed rate base increase for post test year plant should be rejected for the reasons stated in my Direct and Surrebuttal Testimony.
- UNSG's proposed increase to rate base related to removing a portion of the cost-free, non-investor supplied capital in the form of Customer Advances should be rejected for the reasons stated in my Direct and Surrebuttal Testimony.
- UNSG's attempt in its Rebuttal Testimony to increase the amount of Cash Working Capital in rate base by over $2 million for a post-test year change in the payment lag for purchased gas expense in retaliation to a Staff recommendation is one-sided and should be rejected for the reasons stated in my Surrebuttal Testimony.
- The adjustments to the specific components of Accumulated Deferred Income Taxes shown in Attachment RCS-2, Schedule B-2, filed with my Direct Testimony should be adopted for the reasons stated in my Direct and Surrebuttal Testimony. That adjustment decreases rate base by $423,669.
- If the Commission deems that the debit-balance ADIT of $170,414 related to the Accrued Vacation and Accrued Pension Liabilities should be included in rate base, then the corresponding balances in the Accrued Vacation and Accrued Pension Liability accounts, amounting to $441,483, should reduce rate base, to recognize this non-investor supplied cost-free capital, for a net reduction to rate base for these accrued liability items of $271,069.

Adjusted Net Operating Income
The following adjustments to UNSG's proposed revenues, expenses and net operating income should be made:

- UNSG's proposed revenue annualization, which attempts to decrease test year revenue, should be rejected for the reasons stated in my Direct and Surrebuttal Testimony.
- The adjustments to Incentive Compensation Expense, Stock-Based Compensation, and Supplemental Executive Retirement Plan Expense recommended in my Direct Testimony should be made for the reasons stated in my Direct and Surrebuttal Testimony.
- UNSG's expense for the gas utility industry association, the American Gas Association, should be reduced by 40 percent, not the 4 percent proposed by UNSG, for the reasons stated in my Direct and Surrebuttal Testimony.
- A normalized allowance for UNSG's non-rate case Outside Legal Expense should be determined that takes into account changed circumstances and does not rely primarily on backward-looking historical information, as described in my Direct and Surrebuttal Testimony.
- UNSG's Fleet Fuel Expense for the test year was abnormally high, reflecting extreme high levels of gasoline prices, as described in my Direct and Surrebuttal Testimony. A normalized level should be used for ratemaking purposes, based on average usage and average prices for the period January 2006 through June 2009, as described in my Surrebuttal Testimony and shown on Attachment RCS-7, Schedule C-8 Revised.
- UNSG's proposed Rate Case Expense is excessive in comparison to the Commission allowed amounts in the last UNS Gas and the last UNS Electric rate cases. Rate Case Expense charged to UNSG's ratepayers should be limited to n annual allowance of $100,000 based on a total amount of $300,000 normalized over a three-year period as described in my Direct and Surrebuttal Testimony.
- UNSG's proposed increase to test year expense for a projected 2010 pay increase should be rejected for the reasons stated in my Direct and Surrebuttal Testimony.
- A known and measureable postage rate increase occurred in May 2009. The amount of postage expense increase of approximately $22,000 corresponding with RUCO's recommended level of test year customers is shown on Attachment RCS-7, Schedule C-13.

I. INTRODUCTION

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

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Residential Utility Consumer Office ("RUCO").

Q. Which UNS Gas rebuttal testimony do you address in your Surrebuttal Testimony?

A. I address certain adjustments and issues that were discussed in the Rebuttal Testimony of these UNS Gas, Inc. ("UNSG", "UNS Gas," or "Company") witnesses: Dallas Dukes, Bentley Erdwurm, Kentton Grant, David Hutchens, and Karen Kissinger. These issues include rate base adjustments, operating income adjustments and fair value rate of return.

Q. Have you prepared any exhibits to be filed with your Surrebuttal Testimony?

A. Yes. Attachments RCS-7 through RCS-10 contain the results of my analysis and copies of selected documents that are referenced in my surrebuttal testimony, respectively.

II. REVENUE REQUIREMENT

Q. What revenue increase has been requested by UNSG?

A. UNSG originally requested an increase in base rate revenues of $9.480 million, or approximately 6.1% percent, based on adjusted gas retail revenues at current rates of $51.158 million. UNSG witness Dukes states at page 3 of his rebuttal testimony that with the additional adjustments UNSG is now proposing, the Company's revenue requirement could increase by approximately $146,000; however, the Company is not requesting a revenue requirement higher than proposed in its Application. Mr. Dukes' rebuttal Exhibit DJD-1 shows the "UNSG Revised 7/8/09" requested increase in the gross revenue requirement as the same $9.480 million as in UNSG's original Application.

Q. Do you have any initial comments on UNSG's rebuttal filing?

A. Yes. In view of the poor economy and what some believe is the worst economic climate since the Great Depression, it is disappointing that UNSG continues to take a "business as usual" approach to this rate case, continuing to argue for a rate increase that is no lower than its initial filing, and continuing to include items such as Supplemental Executive Retirement Plan ("SERP") expense, incentive compensation, stock-based compensation, and budgeted 2010 pay increases that apparently have not been reduced in response to the economic conditions. Other utilities have responded differently under such circumstances and, as I will discuss in my testimony, have removed items such as SERP and incentive compensation, and have taken other steps such as freezing non-union and management salaries, removed previously disallowed expenses, and taken other steps in response to the financial crisis.

Q. Have you updated RUCO's recommended revenue requirement at this time?

A. Due to time frame allotted for responding to UNSG's rebuttal testimony I have not prepared a comprehensive update to RUCO's recommended revenue requirement at this time. However, it would be my intention to have such an update available at the time of my appearance at the hearing.

Fair Value Rate of Return

Q. What UNSG Rebuttal Testimony addresses the Fair Value Rate of Return?

A. The Fair Value Rate of Return ("FVROR") is addressed by UNSG witness Kentton Grant. Pages 33-35 of Mr. Grant's Rebuttal Testimony present the Company's criticisms of RUCO's proposed FVROR. Mr. Grant indicates that he found my description of the various FVROR calculation methodologies and related impacts on UNSG's revenue requirement to be helpful, but had the following criticisms:

(1) UNSG wants more than $38,000 of additional revenue under the FVROR versus an Original Cost Rate Base ("OCRB") based calculation.

(2) Lack of explanation for the alternatives.

(3) Failure to consider the financial impact of the FVROR recommendation.

(4) The RUCO FVROR calculations reflect what Mr. Grant believes to be an unreasonably low recommendation from RUCO witness William Rigsby.

Mr. Grant admits with reservations that UNSG is effectively requesting a Return on Equity ("ROE") of 12.58 percent on OCRB. His reservation is that he does not expect the Company to be able to earn the 12.58 percent; consequently, he disagrees that a 12.58 percent ROE would be an excessive rate of return.

I will address items 1-3 and the effective 12.58 percent ROE that is embedded in UNSG's revenue increase request. Mr. Rigsby provides surrebuttal testimony defending his recommended ROE.

Q. Please address the issue of how much additional revenue increase UNSG should receive under the FVROR over and above what the OCRB-based results show.

A. In my direct testimony, I recommended a FVROR-based result that would have given UNSG approximately $38,000 more than an OCRB-based result. In contrast, UNSG apparently seeks an additional $3.62 million "fair value difference" on top of its interpretation of Staff's recommendation and an additional $3.808 million "fair value difference" beyond RUCO's direct filing amount of approximately $734,000.[1] The amount of extra revenue increase, if any, using the FVROR, is a matter that is subject to the discretion and judgment of the Commission. In the current poor economic climate, a modest amount of additional revenue increase to the utility under the FVROR might be justified, but burdening ratepayers with an additional revenue increase of over $3.6 million for FVROR is not warranted.

Q. Please explain the FVROR alternatives that you considered and the basis for your recommendation.

A. Page 2 of Schedule A in Attachment RCS-2 that was filed with my direct testimony shows information concerning the potential impacts on UNSG's revenue deficiency in the current rate case that was considered by RUCO in developing the recommended FVROR recommendation. Similar to information presented by RUCO and Staff to the Commission in a recent remand proceeding, Docket No. W-02113A-04-0616, concerning Chaparral City Water Company, and in some other recent rate cases, I have also presented on Schedule A, page 2, in columns A through D various potential ways of determining a FVROR for UNSG, including:

- Calculation 1 - Reduce Recommended OCRB-Based Return on Equity for Estimated Inflation
- Calculation 2 - Reduce Recommended OCRB-Based Overall Rate of Return for Estimated Inflation
- Calculation 3 - With Fair Value Rate Base Increment at Zero Cost
- Calculation 4 - With Fair Value Rate Base Increment at 1.25%

[1] See UNSG's response to RUCO 11.13 which attempts to add a "fair value difference" of $3.620 million to UNSG's interpretation of Staff's filing and $3.808 million to RUCO's.

The details for each FVROR calculation are shown on Schedule D, page 2.

On Attachment RCS-2, on Schedule A, page 2, in column E, I also presented RUCO's ultimate recommendation of the FVROR and the resulting base rate revenue deficiency. RUCO's recommendation falls within the range of FVRORs developed using various calculation methods, and is near, but not at the low end of that range. I believe that this information and RUCO's recommended FVROR in the current UNSG rate case that was made after considering these alternatives appropriately fulfills the requirement of the Arizona Constitution that the Commission must base rates on a utility's fair value. The four FVROR methods on Attachment RCS-2, Schedule A, as well as the OCRB-based result, have been presented for the Commission's informed consideration, given the analytical framework addressed in Decision No. 70441 and that has been under further development on a case-by-case basis.

The Commission's traditional calculation of return on fair value rate base calculation has been called into question by the Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income in that case had ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution. Guidance for calculating the return on fair value rate base was provided in that Court of Appeals decision. First, the Court of Appeals specifically stated that the Commission was not bound to apply an authorized rate of return that was developed for use with an original cost rate base, without adjustment, to the fair value rate base. Page 9 of the Court of Appeals decision stated that: "Chaparral City … asks that the Commission be directed to apply the 'authorized rate of return' to the fair value rate base rather than to the OCRB, as Chaparral City contends was done here." At page 13, paragraph 17, the Court of Appeals decision stated as follows: "The Commission asserts that it was not bound to use the weighted average cost of capital as the rate of return to be applied to the FVRB. The

Commission is correct." Thus, the Court of Appeals clearly stated that the Commission is not bound to apply to the FVRB the same weighted average cost of capital that was developed for application to the OCRB. At pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision states: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

The Commission reopened Docket No. W-02113A-04-0616 to address such issues in a Chaparral City remand proceeding and, on July 28, 2008, issued Decision No. 70441. In Decision No. 70441, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the Commission can use to determine an appropriate FVROR, including adjusting the weighted average cost of capital ("WACC") to exclude the effect of inflation on the cost of equity, and that the FVROR adopted by the Commission in that case fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process.

In view of the Court of Appeals decision in the Chaparral City case and the subsequent guidance provided by the Commission in other recent decisions on the issue of FVROR, RUCO has appropriately adjusted the weighted cost of capital to derive a FVROR to apply to the utility's FVRB. My direct testimony presented RUCO's derivation of the fair value return on fair value rate base calculations in view of the Court of Appeals decision concerning Chaparral and the Commission's Decision No. 70441 in the Chaparral remand case, as described above. Specifically, Attachment RCS-2, Schedule D, page 2, shows the derivation of four FVROR calculations that were considered by RUCO. Mr. Smith's Attachment RCS-2, Schedule A, page 2, in columns A through D, summarizes the resulting revenue deficiencies that would be produced in the current UNSG rate case from each of those FVROR figures. Schedule A, page 2, Column E shows RUCO's recommended FVROR and the resulting revenue deficiency. This FVROR recommendation was also applied to the FVRB on Schedule A, page 1, column D.

Additional explanations of my analysis were provided to UNSG in response to discovery, and are summarized here for ease of reference.

Calculation 1: This calculation is equivalent to the calculation method used by the Commission in setting the FVROR in Decision No. 70441 in the Chaparral City remand proceeding. However, it is clear that the Commission left itself with flexibility to consider the results of various calculations and in fact considered the results of various methods in that case and selected one that made sense in the context of that case. The Commission reopened Docket No. W-02113A-04-0616 to address such issues in a Chaparral City remand proceeding and, on July 28, 2008, issued Decision No. 70441. In Decision No. 70441, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the Commission can use to determine an appropriate FVROR, including adjusting the weighted average cost of capital ("WACC") to exclude the effect of inflation on the cost of equity, and that the FVROR adopted in that particular proceeding fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process. Based on the result shown on Schedule A, page 2, the Calculation 1 method would provide UNSG with an unjustified windfall of over $3.8 million and thus was evaluated as being "way too high." Specifically, in the context of the current UNSG rate case, the Calculation 1 method produces a rate increase that is way too high and is therefore not being recommended by RUCO.

Calculation 2: This calculation reflects one of the methods discussed in the Chaparral City remand case by RUCO's witness in that case, Ben Johnson. This method is based on an analysis that there is an inflation component in both the cost of equity and the cost of debt, i.e., in the WACC. Dr. Johnson's testimony in that case contained additional discussion of the reasons for this method. Decision No. 70441 indicates that the Commission has discretion in determining the FVROR in each case. Additional testimony from RUCO witness William Rigsby in the current UNSG rate case provides further support for the fact that there is an inflation component to the cost of debt. The result of Calculation 2 in RUCO's filing would have produced a rate decrease, which did not seem to be appropriate in the context of the current UNSG rate case, given the OCRB-based revenue requirement and the results of the other FVROR based methods.

Calculation 3: This could be viewed as mathematically equivalent to a zero weighting of FVRB in the determination of revenue requirement. In other words, applying a zero cost of capital to the FV rate base increment that is not financed with any debt or equity capital that has been recorded on the utility's books could be formulated in the context of an algebraic formulation that produces a required net operating income amount presenting the same result as applying the WACC to OCRB. The reason for differences between the required net operating income result under these two approaches is attributable to rounding This method is nevertheless appropriate for Commission consideration because it is logically supported by appropriate economic, financial and ratemaking principles, which include that the FVRB increment is not financed with any debt or equity capital on the utility's books, and thus could be viewed for ratemaking purposes as being supported entirely by zero-cost capital. The economic and financial logic supporting the application of a zero cost rate to the FV Increment of the capital structure includes the following: the weighted average cost of capital is conceptually suited to apply to an OCRB; the OCRB is based largely on amounts recorded on the utility's books; the OCRB is financed with debt and equity that are recorded on the utility's books; the difference between the FVRB and the OCRB has not been financed by any identifiable debt or equity capital on the utility's books; rate base elements that are supported by zero cost capital typically do not earn a return since there is no investment by the utility and allowing a return could thus produce windfall profits. In other words, as shown on Attachment RCS-2, Schedule D, filed with Mr. Smith's direct testimony, the weighted average cost of capital developed for the application to the OCRB under Calculation 3 is appropriately adjusted for application to a FVRB by recalculating the capital structure ratios and assigning a zero financing cost to the FV Increment, which is not supported by debt and equity on the utility's books. Additional explanation of the support for this method, from a financial perspective, has been presented in the direct and surrebuttal testimony of David Parcell, who presented testimony on behalf of the Commission Staff in the Chaparral City remand case, in Docket No. W-02113A-04-0616. The result of Calculation 3 would have produced a rate increase that was slightly below the OCRB-revenue requirement in RUCO's filing. This result did not seem to be appropriate in the context of the current UNSG rate case, given the OCRB-based revenue requirement and the results of the other FVROR based methods.

Calculation 4: This calculation is based on Staff recommendations that have been developed in a series of rate cases since the Court of Appeals Decision in the Chaparral City rate case in which the FVROR was an issue. It applied a rate of 1.25 percent to the FVRB increment. The 1.25% is the midpoint of a range from zero to 2.5 percent.[2] The low end of the range, zero, is based on the fact that the FVRB increment is not financed by any debt or equity capital on the utility's books. An estimate of inflation

[2] (0 + 2.5) /2 = 1.25.

was developed for purposes of RUCO's use in the current UNSG case by RUCO witness William Rigsby as shown on his Schedule WAR – 1, page 4. As shown there, 2.5% is the average inflation rate from the data set used by Mr. Rigsby for 2001-2008, and this could be viewed as a very conservative estimate of inflation embedded in the risk-free interest rate, since the indicated inflation component for more recent years in the data series was higher: e.g., 2008 was 3.66 percent. The estimate of the real risk-free rate of return was supplied by RUCO witness William Rigsby and is based on his estimate of the risk free rate of return less inflation. Based on the result shown on Attachment RCS-2, Schedule A, page 2, the Calculation 4 method would provide UNSG with an unjustified windfall of almost $1.49 million and thus was evaluated as being "too high."

In summary, as explained in detail above, the criteria used was informed judgment and a detailed attempt to apply the guidance articulated in the Court of Appeals remand decision and in Commission Decision No. 70441. The determination of FVROR is at best an estimation and not an exact science. The goal is to provide the Company with an opportunity to earn a reasonable rate of return, not to provide the Company with an excessive rate increase or a windfall. Based on my direct knowledge of how the FVROR has been under further development on a case-by-case basis in some of the other cases that have attempted to address this issue subsequent to the Court of Appeals remand decision, I believe that RUCO's presentation in the instant UNSG rate case, and the resultant recommendation fully complies with such guidance and results in a reasonable and fair rate of return when all relevant and appropriate factors are considered.

Q. Please explain how UNSG is effectively requesting an ROE of 12.58 percent.

A. On its Schedule D-1, UNSG purported to be requesting a return on equity ("ROE") of 11.0 percent, and an overall rate of return of 8.75 percent. However, on its Schedule A-1, line 7, UNSG has applied an overall rate of return of 9.54 percent to its proposed OCRB. On

Schedule D, I have shown a calculation based on the capital structure UNSG used for developing its recommended rate of return of 9.54 percent on OCRB. This calculation shows that the equivalent return on equity ("ROE") implicit in UNSG's request for 9.54 percent on OCRB is an ROE of 12.58 percent, as summarized below:

UNS Gas Proposed to Show Equivalent Requested ROE

Capital Source	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
Long-Term Debt	50.01%	6.49%	3.25%
Common Stock Equity	49.99%	**12.58%**	6.29%
Overall Cost of Capital	100.00%		9.54%

Q. **Would an ROE of 12.58 percent be excessive?**

A. Yes. It would substantially exceed the ROEs for OCRB recommended by the witnesses for RUCO and Staff in this case.

Q. **Mr. Grant also criticizes RUCO for alleged failure to consider the financial impact of the FVROR recommendation. Please respond.**

A. Mr. Rigsby addresses this in his Surrebuttal Testimony. In addition, I address concerns about Mr. Grant's attempt to use questionable forecasts that do not reflect typical ratemaking adjustments as a basis for evaluating the recommendations made by Staff and RUCO in this case. Mr. Grant appears to be relying on financial forecasts on page 24 of his Rebuttal Testimony, which have revised forecasts originally presented on page 27 of his Direct Testimony. I would caution against placing much reliance upon forecasts as the basis for ratemaking treatments because forecasts are subject to change and can be inaccurate.[3] Additionally, the forecasts presented by Mr. Grant should not replace the Commission's traditional test year analysis, with unaudited future projections. Moreover,

[3] For example, Mr. Grant's rebuttal, at page 15, in the prior UNSG rate case stated that in 2003, the Company could not foresee the amount of capital investment needed to serve customer growth and system improvement needs, and that "it was difficult to predict the future impact of regulatory lag on UNS Gas."

Mr. Grant's projections do not reflect ratemaking adjustments that would typically be required by the Commission.[4] Without reflecting the impact of the specific adjustments which cause that difference (i.e., without also reflecting the reasons for the difference) is questionable and unlikely to produce reliable forecasts that are meaningful and relevant for ratemaking purposes. In states that utilize future test years, where projections are made beyond the historical period, adjustments are typically made to all of the components of the ratemaking formula which impact the level of revenues; however, Mr. Grant's projections apparently do not incorporate this. In jurisdictions that utilize future test years, when adjustments are made for disallowed expenses, the disallowed expenses are removed from the future test year. To the extent that Mr. Grant is attempting to use his revised financial forecasts as some kind of surrogate for a future test year, or as some kind of test of the reasonableness of the parties' differing recommendations, his comparisons do not appear to reflect the adjustments to rate base or expenses that contribute to Staff or RUCO recommending a different level of revenue increase than has been requested by the Company.

III. RATE BASE

ADJUSTMENTS TO ORIGNAL COST RATE BASE

Q. Please discuss RUCO's adjustments to UNSG's proposed original cost rate base.

A. RUCO has made five adjustments to UNSG's proposed original cost rate base. These have been designated as RUCO Adjustments B-1 through B-6. Each adjustment is discussed below.

B-1 Post Test Year Plant

Q. What has UNSG proposed for Post-Test Year Plant?

[4] See, e.g., UNGS' response to RUCO 11.38.

A. UNS Gas has proposed to include $1.528 million of Post Test Year Non-Revenue Producing Plant in Service (i.e., Construction Work in Progress ("CWIP")) in rate base. RUCO adjustment B-1 removed that amount from rate base.

Q. Please discuss UNS Gas' reasons for disagreeing with your recommendation to remove such post test year plant in rate base.

A. As described in the Rebuttal Testimony of UNS Gas witness Dallas Dukes at pages 4-5:

(1) The post test year plant is not CWIP.

(2) Previous Commission decisions have included non-revenue producing post-test year plant in rate base.

(3) Mr. Dukes believes that the reason the Commission rejected UNSG's request for post test year plant in its last rate case (Decision No. 70011) was that UNSG made no attempt to segregate revenue-producing plant from non-revenue producing plant, and UNSG has attempted to address this in the current case.

Q. IS UNSG's request for post test year plant based on CWIP balances at the end of the test year?

A. Yes. It is a subset of CWIP.[5] As such, it suffers from all of the concerns associated with the inclusion of CWIP in rate base, including:

1) Inclusion of CWIP or post test year plant in rate base is an exception to the Commission's normal practice, and UNS Gas has not met its burden of proof showing why it requires such an exceptional ratemaking treatment.

[5] See, e.g., UNSG's response to RUCO 11.28d: All "post test year plant" that UNSG is requesting in rate base was in CWIP as of the end of the test year.

2) The CWIP was not in service at the end of the test year. As of June 30, 2008, the projects were not serving customers.

3) The Company has not demonstrated that the portion of its June 30, 2008 CWIP balance was for non-revenue producing and non-expense reducing plant. Much of the construction appears to be for plant which can be related to serving customer growth, and/or can reduce expenses for maintenance.

4) Revenues have not been extended beyond the test year to correspond with customer growth. Hence, including the investment in rate base, without recognizing the incremental revenue it supports or the expense reductions such plant additions could enable, would be imbalanced.

Q. Is inclusion of post test year plant in rate base up to the discretion of the Commission?

A. Yes, it is. RUCO's understanding is, in specific instances, the Commission has allowed some water utilities to include post test year plant in rate base, but the Commission's general practice, particularly for energy utilities, such as UNSG, has been to not allow post test year plant or CWIP to be included in rate base. As such, the Commission denied the Company's request for CWIP in rate base in its last rate case.[6]

Q. Does RUCO agree with the proposal of UNS Gas to include post test year plant in rate base in the current case?

[6] Decision No. 70011, Docket No. G-04204A-06-0463

A. No. In general, RUCO does not favor inclusion of post test year plant in rate base unless the utility demonstrates compelling reasons to justify this exceptional ratemaking treatment.

Q. What criteria did UNSG use to select the portion of its June 30, 2008 CWIP balance for its post test year plant in rate base claim in the current case?

A. As described in UNSG's response to RUCO 11.30b and c, certain UNSG and affiliate personnel were given verbal instructions to identify "non-additional" revenue producing plant that was not being installed for the purpose of meeting customer growth and investments that would have been made whether UNSG added additional customers or not. Concerning mains and services, UNSG attempted to identify replacements whose primary purposes were to serve existing customers and would have been replaced regardless of customer additions.

As such, the criteria used by UNSG to select the June 30, 2008 CWIP balance for its post test year plant in rate base claim in the current case was a bit loose and apparently did not consider whether the project would be expense reducing or whether it would help facilitate service to customers added after the test year.

Q. Why is it important that the plant be both non-revenue producing and non-expense reducing?

A. If post test year plant is revenue producing or supports the addition of customers beyond the end of the test year, or if it enables the reduction of expenses, such as the replacement of aging mains and services, or the replacement of older transportation of equipment could do, then a mis-match would result. Rates would be increased for the inclusion of such plant in rate base; however, revenue would not be extended for new customers and expense reductions would not be reflected. UNSG's response to data request RUCO 11.18 identifies various post test year expense reductions, including reduced overtime, reduced vehicle maintenance, reduced vehicle depreciation, etc., none of which have been reflected. It is imbalanced to include in rate base plant that was not in service during the test year and to ignore expense reductions. Rather than attempt to make pro forma adjustments for the post test year expense reductions, the Company's post test year plant adjustment should be rejected.

Q. Please elaborate on how including post test year plant in rate base is an exceptional ratemaking treatment and why the circumstances in this case do not warrant such treatment.

A. Post test year plant, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it was not used or useful in delivering gas service to the Company's customers. In Arizona, the ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. Arizona's ratemaking process therefore excludes such plant from rate base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement. In the current UNS Gas rate case, the test year is June 30, 2008, and the construction projects the Company seeks to include in rate base were not providing service during that period. As a general ratemaking principle, such post test year plant should be excluded from rate base.

Additionally, some of the plant being added, such as main replacements, could result in a reduction in maintenance expenditures which would not be reflected in the test year. The inclusion of plant in rate base, therefore, creates an imbalance in the relationships between rate base serving customers and the revenues being provided to the utility from customers who were taking service during the test year. Consequently, such plant should not be allowed in rate base unless there are very compelling circumstances which would warrant an exception to the general rule[7]. In the current case, UNS Gas has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding such plant from rate base. It is not appropriate to include the plant in rate base, particularly as the projects may result in additional revenues or cost savings which have not been reflected in the test year ended June 30, 2008.

Q. How does plant that is placed into service between rate case test years typically get reflected in the regulatory process?

A. If the plant is used to serve new customers, the utility receives revenue from those customers. If the plant helps the utility reduce expenses, such as maintenance, the utility benefits from such cost reductions during the intervening period. Once the plant is recognized in rate base in a test year, and rates are reset, the utility earns a cash return on

[7] RUCO is aware of only one instance in which the Commission has allowed CWIP in rate base for an energy utility. That occurred in the early 1980s when the Commission considered the costs associated with the Palo Verde Nuclear Plant. Because the up-front costs were so great, the Commission allowed CWIP in rate base in order for the plant to be built.

the plant investment, less accumulated depreciation. The related revenues and expense impacts, including known and measurable expense reductions enabled by the plant, are then also recognized in the ratemaking process.

Q. Did the Commission address this issue in UNS Gas' last rate case?

A. Yes. The Commission's decision in Decision No. 70011 addressed the issue of post-test year plant at pages 7-8, and reached the following conclusion:

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

Q. Could the replacement of old mains and services reduce maintenance cost?

A. Yes.[8]

[8] See, e.g., UNSG's response to RUCO 11.28a

Q. Could the additional transportation equipment help serve customer growth and/or reduce maintenance costs?

A. Yes.[9]

Q. UNS Gas witness Dukes cites to five decisions on page 4, line 18, of his Rebuttal Testimony as the support UNSG is relying on for Commission decisions that have included post-test year plant in rate base. Are any of those decisions for energy utilities?

A. No, they all pertain to water utilities, as admitted by UNSG in response to RUCO 11.28e. UNSG is not a water utility, and has not cited any decisions allowing post test year plant for an energy utility in its Rebuttal Testimony, as admitted in response to RUCO 11.28f and g, respectively. Moreover, the Commission has denied the inclusion of post-test year plant in rate base in other decisions, including the decisions in UNSG's and its affiliate, UNS Electric's last rate cases.

Q. Is there any other deficiency related to UNSG's proposed treatment of post-test year plant?

A. Yes. UNSG has apparently failed to reflect a lower amount of rate base related to the application of 2008 bonus tax depreciation on the post-test year plant. Qualifying plant additions in 2008 (and 2009) are eligible for 50 percent bonus tax depreciation. UNSG's CONFIDENTIAL response to RUCO 11.39(e) claims that [**BEGIN CONFIDENTIAL**]

[9] See, e.g., UNSG's response to RUCO 11.28b and c.

[**END CONFIDENTIAL**] However, this response by UNSG fails to recognize that the Company did include, as a pro forma adjustment, additional depreciation related to the post test year plant. Consequently, the Company's proposed treatment of post test year plant fails the matching principle by failing to reflect the increased ADIT related to such post test year plant, which would include the impact of bonus tax depreciation, and thus overstates rate base. UNSG's CONFIDENTIAL response to RUCO 11.39 contains some additional information from which a rate base adjustment for ADIT related to the post test year plant could presumably be derived. Such an adjustment is not necessary as long as the Commission rejects UNSG's proposal to include post test year plant in rate base. However, if that adjustment were to be allowed, a related adjustment to increase ADIT and decrease rate base, related to the pro forma book depreciation and the bonus tax depreciation on such post test year plant, would need to be made.

Q. Please summarize your recommendation concerning post test year plant.

A. UNS Gas's proposal to treat a portion of its CWIP at the end of the test year as if it were plant in service should be rejected for the reasons stated in my direct testimony and above.

B-2 Customer Advances for Construction

Q. What is the dispute concerning Customer Advances?

A. UNSG seeks to increase rate base by $589,152 by removing a portion of its actual June 30, 2008 Customer Advances. Customer Advances are typically reflected as a reduction to utility rate base. Staff and RUCO have recommended reflecting the full end-of-test-year balance for Customer Advances as the reduction to rate base.

Q. Why has UNSG sought to remove $589,152 from Customer Advances?

A. Mr. Dukes' Rebuttal Testimony at page 6-7 claims that this amount of Customer Advances relates to projects that are not in rate base as of the end of the test year.

Q. Was a similar claim made by UNSG in its last rate case?

A. Yes. As one of UNSG's supporting arguments for its attempt to include CWIP in rate base, UNSG had also attempted to have a portion of Customer Advances excluded from the determination of rate base, using similar arguments from the prior case.

Q. Did the Commission make that UNSG-proposed adjustment in UNSG's last rate case?

A. No. In UNSG's last rate case, the Commission appropriately deducted the full amount of Customer Advances from rate base. This issue is addressed in Decision No. 70011 at pages 8-10, and the Commission reached the following conclusion:

> We agree with Staff and RUCO that advances represent customer-supplied funds that are properly deducted from the Company's rate base. Indeed, the Commission's own rules contemplate that such a deduction is required, as Staff witness Smith testified. Had UNS not requested the inclusion of CWIP in rate base, a ratemaking treatment that is only afforded under extraordinary circumstances (and apparently has not occurred for more than 20 years), there would presumably not have been an issue raised by the Company with respect to an alleged "mismatch" between exclusion of CWIP and deducting advances from rate base. The Company's attempt to frame this issue as one in which it is being treated in a discriminatory manner is unpersuasive.
>
> As we have stated in prior cases, regulated utility companies control the timing of their rate case filings and should not be heard to complain when their chosen test periods do not coincide with the completion of plant that may be considered used and useful and therefore properly included in rate base. We believe our conclusions regarding UNS's CWIP-related proposals are entirely consistent with the treatment that has been afforded to other utility companies regulated by the Commission and provide a result that is fair to both the Company and its customers.

Q. Does UNSG have the use of the money provided for in Customer Advances?

A. Yes. UNSG has the use of such money, which is fungible. UNSG does not hold the Customer Advance money in an escrow account. It represents non-investor supplied capital that should be deducted from rate base.

Q. Please respond to Mr. Dukes' rebuttal at pages 6-7?

A. Mr. Dukes first agrees that Customer Advances are non-investor supplied capital, and he agrees that they should be deducted from rate base so that the Company does not earn a return on investments it does not make. However, Mr. Dukes' proposal (1) does not deduct the full amount of Customer Advances from rate base, and (2) UNSG does not deduct Customer Advances in its calculation of Allowance for Funds Used During Construction ("AFUDC") either, thus, if Mr. Dukes' recommendation were to be adopted, UNSG would earn a return on investments supported by non-investor supplied capital. Mr. Dukes has ignored the fact that UNSG records AFUDC on construction projects. The AFUDC is calculated on the CWIP balance, without any reduction for Customer Advances. That is, UNSG does not reduce CWIP by Customers Advances prior to calculating AFUDC. The AFUDC represents the return to the Company during the construction period. If the Customer Advances related to CWIP are not deducted in full from rate base, this creates an inappropriate situation where the utility would earn a return on the non-investor supplied capital because the Customer Advances related to CWIP have not been reflected as either reduction to rate base or as a reduction to CWIP for purposes of the AFUDC calculation. Since the Customer Advances do not reduce the CWIP balance upon which AFUDC is calculated, they must be reflected in full as a reduction to rate base. To do otherwise would fail to appropriately recognize the Customer Advances as a source of non-investor supplied capital.

Q. Do you agree with UNSG's claim that some Customer Advances should be excluded in the determination of rate base?

A. No. Because Customer Advances represent non-investor supplied capital, they should be reflected as a deduction to rate base. Additionally, research conducted in the context of UNSG's last rate case did not reveal any instance in which CWIP for a major utility was excluded from rate base and customer advances were not also reflected as a deduction to rate base. Additionally, the Commission's rules at A.A.C. R14-2-103, Appendix B, Schedule B-1, require companies to reflect Advances as a deduction from rate base. Consequently, the rate base deduction for Customer Advances should reflect the full end-of-test year amount. For the reasons described in my Direct Testimony and above, the adjustment proposed by UNSG should be rejected. Customer Advances proposed by UNSG should be increased by $589,152 and rate base reduced by this amount.

B-4 Cash Working Capital

Q. Have you reviewed the Company's revised request for a cash working capital allowance?

A. Yes. The Company had originally proposed a cash working capital allowance of approximately $1,568, i.e., under $1,600. Now, in rebuttal, UNSG is seeking a cash working capital allowance of over $2.18 million. It appears that in response to an adjustment by Staff witness Fish that attempts to increase the Company's purchased gas payment lag, UNSG is now proposing a substantially shortened lag.

Q. Do you agree with the Staff's proposed gas purchase payment lag?

A. No. The gas purchase payment lag proposed by Staff witness Fish is inadequately supported, and for that reason should not be adopted.

Q. What support in its Rebuttal Testimony did UNSG provide for the drastically different new gas purchase payment lag and much higher cash working capital allowance?

A. Not much. The Rebuttal Testimony of UNSG witness Dukes on this major change in the Company's working capital calculation consists of one paragraph at page 2 identifying the Company's new, much higher cash working capital request, and a rather vague discussion at page 8.

Q. Did UNSG provide additional information in response to RUCO discovery?

A. Yes. UNSG provided its rebuttal workpapers and Excel files in response to RUCO 10.1. UNSG provided some additional information in response to RUCO 11.33.

Q. Should the drastically higher new cash working capital allowance proposed by UNSG for the first time in its rebuttal testimony be adopted?

A. No, it should not be adopted, for several reasons including the following:

(1) The purchased gas payment lag for the test year is documented at Company workpapers UNSG 0571/01980 through 02063 and shows a weighted lag of 27.89 days.[10]

(2) The purchased gas payment lag payment lag of 27.89 days UNSG used in the current case is fairly consistent with the lag used by UNSG in its prior rate case of 30.97 days for this item.[11]

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[10] A copy of those UNSG workpapers was provided in on CD in response to Staff data request JMK 1.1. Because of the volume, those UNSG workpapers are not included.
[11] See, e.g., UNSG's response to Staff data request TF 6.27.

(3) UNSG's proposed change would reach outside of the test year for one item that increases the revenue requirement without considering other offsetting items.

(4) The coverage of the post-test year change in gas procurement responsibility from BP Energy to the affiliate, TEP, which was described in Staff's prudence review of UNSG's gas procurement, indicated that this should produce a benefit to UNSG's ratepayers, not an additional revenue requirement burden.

(5) UNSG has not demonstrated that a change in the payment terms is permanent.

Q. **Please explain how the purchased gas payment lag for the test year is documented at Company workpapers UNSG 05741 / 01980 through 02063 and shows a weighted lag of 27.89 days.**

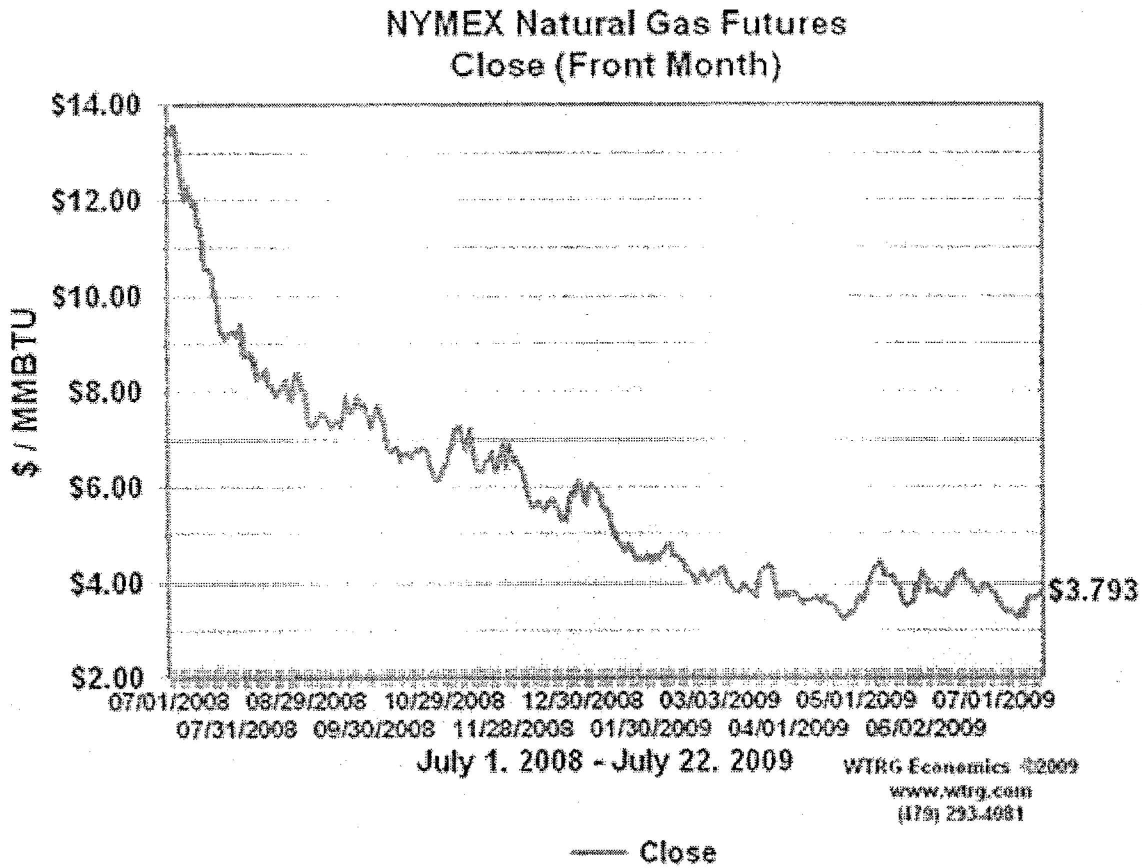
A. That documentation shows in detail how the gas purchases for the test year produced the weighted lag of 27.89 days, based on dollar day weighting of purchases from BP Energy Company, El Paso Natural Gas, and Transwestern Pipeline Company.[12]

Q. **Please explain how UNSG's proposed change would reach outside of the test year for one item that increases the revenue requirement without considering other offsetting items.**

A. The test year consists of the 12 month period ended June 30, 2008. UNSG's revised purchase gas payment lag calculation, which was provided in response to RUCO 10.1 is based on July 2008 through May 2009 information for gas purchases from BP Energy, but retains the Company's originally calculated lags for El Paso and Transwestern. Only by going outside of the test year and into subsequent months has UNSG derived its new proposed and much shorter gas purchase payment lag. However, when applying the gas

[12] Because of the volume, the UNSG workpapers for the purchased gas payment lag are not being included in Attachment RCS-8; however, a one-page summary, from UNSG's response to data request RUCO 10.1, which shows Mr. Dukes' supporting workpaper that summarizes the derivation of the 27.89 day lag contained in UNSG's lead lag study, and the much shorter lag that UNSG has proposed in its Rebuttal Testimony, is included in Attachment RCS-7.

purchase lag in its lead-lag study, UNSG failed to apply it to the same $87,528,793 purchased gas expense amount from UNSG's original filing[13], and thus failed to capture and reflect declines in the cost of natural gas that have occurred subsequent to the test year. As shown in the following graph, which shows NYMEX future prices, natural gas costs have declined considerably subsequent to the test year:



[13] See UNSG Schedule B-5, page 3, line 7, column B.

By applying a new much shorter payment lag based on post test year-derived to the same amount of test year natural gas purchase expense in its original filing, UNSG has distorted the impact upon rate base in a one sided manner. UNSG's calculation would overstate the amount of cash working capital and revenue requirement.

Q. The NYMEX graph shows the decline in natural gas prices generally since the test year. Do you have specific information on post test year natural gas cost decreases that UNSG has failed to reflect?

A. Yes. The following table summarizes the natural gas purchases from BP that UNS Gas used (1) to derive its originally proposed test year payment lag and (2) to derive its significantly shortened payment lag. Because UNSG only used an 11-month period (July 2008 through May 2009) for its new proposed lag, the comparison only uses the comparable 11 months from the test year (i.e., July 2007 through May 2008):

Gas Purchase Payments to BP Energy	
59,683,901	July 2008 - May 2009
102,031,354	July 2007 - May 2008
(42,347,453)	Dollar Change
-42%	Percent Change

Source: RUCO 10.1 UNSG Purchase Gas Lag Days Rebuttal Excel file

As shown, the gas purchased from BP Energy have decreased by over $42.3 million, or by approximately 42 percent, based on the comparison of these two 11-month periods.

Q. Are there other post test year cost decreases that UNSG has failed to reflect?

A. Yes. There are a number of post test year cost decreases that UNSG has failed to reflect.

UNSG's response to RUCO 11.18 identifies savings in labor costs, meter reading, repairs and maintenance, vehicle maintenance, training and travel, communications and vehicle depreciation, which have not been reflected in the test year.

UNSG's response to RUCO 11.19 identifies an annual cost reduction related to using Walmart for customer payments of approximately $42,000.

UNSG's response to RUCO 11.20 identifies annual cost reductions from UNS Gas lobby office closings.

Q. How was the post-test year change in responsibility for gas procurement addressed in Staff's prudence review of UNSG's purchasing?

A. The testimony of Staff witness Rita Beale addressed a prudence review of UNSG's gas procurement operations and apparently focused on the period from January 2006 to June 2008, with some discussion of post-test year changes. Page 6 of Ms. Beale's testimony, for example, mentions that: "Contractually, gas procurement services ended with BP Energy Services on August 31, 2008 and began in TEP Wholesale Department starting September 1, 2008. As a result, BP's role changed to become one of a number of suppliers canvassed by UNS Gas to purchase gas."

Q. Wasn't the post test year transfer of gas procurement from BP Energy to UNSG's affiliate, TEP, expected to provide net <u>benefits</u> to UNSG ratepayers?

A. I thought so, based on the Direct Testimony of Staff witness Beale at pages 5-8, including this testimony at page 8:

> Q. Are there any other benefits that derive to UNS Gas ratepayers?
> A. UNS Gas has gained the benefit of first hand price discovery by virtue of TEP's direct participation in the market, whereas formerly BP was the entity facing the market. UNS Gas also retains the choice of changing AMA partners should market conditions warrant, both of which should help lower the gas supply and transport costs over the long term. There should be increased accountability for decision-making during severe and critical pipeline operating conditions. Sharing of the cost of gas procurement operations with two UniSource entities, Tucson Electric and UNS Electric is another benefit. UNS Gas's load is winter peaking versus summer peaking for the electric companies, so they are a natural complement. Other benefits are related to credit risk management which is essential to lock-in purchases of gas in the forward markets. UNS Gas's

> counterparty credit risk is theoretically more diversified by using multiple gas suppliers, and UNS Gas should be able to access a greater amount of credit by using multiple suppliers.

Q. Is the substantial increase in its request for cash working capital consistent with the post test year changes in gas procurement functions producing a net benefit to ratepayers?

A. No. The attempt in UNSG's rebuttal testimony to reflect only one post-test year change in its gas procurement, to significantly increase its cash working capital allowance, without considering other offsetting changes and benefits to ratepayers produced by post-test year changes in the gas procurement function, and/or the post test year declines in the cost of natural is thus one-sided and inappropriate.

Q. Has UNSG demonstrated that a change in the gas purchased payment terms is permanent?

A. No. Mr. Dukes' Rebuttal Testimony at page 8 mentions that the payment terms were adjusted because of credit limitations. Moreover, UNSG is a winter-peaking gas distribution company, so its exposure to gas suppliers is highest during the winter months of November through April. A temporary adjustment in payment terms to twice-per-month payments to BP Energy had occurred in the previous winter (December 2007 – January 2008) which then reverted back to a monthly payment and that is reflected in the test year gas purchase payment lag. After exceeding its credit limit with BP Energy, UNSG agreed to more frequent payments (twice monthly) and a standby letter of credit so UNSG could continue to enter into new transactions with BP Energy. A number of alternatives are available in such a situation. As described in the response to RUCO 11.27k:

> UNS Gas could make more frequent payments of amounts owed for gas supplied, could provide a standby letter of credit from a financial institution, or could curtail

> doing new business with the supplier, or a combination of these actions. The decision to provide a letter of credit vs. make prepayments depends on several factors including available credit under its revolving credit facility to issue letters of credit, the cost of issuing letters of credit, the amount of available cash on hand, and the interest rate that could be earned on the investment of excess cash.

UNSG has presented no analysis of the impact of each of these factors from the ratepayers' perspective and has not demonstrated that agreeing to more frequent payment terms was the least cost solution from ratepayers' perspective. Some of the other alternatives, such as incurring the cost of a letter of credit in a non-test year period, may not have had any impact on test year costs or ratepayers. Finally, as stated in response to RUCO 11.27(o): "As long as the vendor's total exposure to UNS Gas is within the credit limit established for UNS Gas, UNS Gas may pay for purchased gas on a monthly basis." Based on all of this, UNSG has failed to establish that payments every two weeks for the purchase of natural gas is permanent, or even is an impact that UNSG's ratepayers should be held responsible for.

Q. Please summarize your recommendation of the purchase gas payment lag that should be applied for purposes of computing cash working capital in the current UNSG rate case, which uses a test year ended June 30, 2008.

A. The payment lag of 27.89 days that is documented in the Company's workpapers should be used. UNSG's attempt to substantially revise this lag in rebuttal and increase costs to ratepayers based on an isolated impact of a post-test year change should be rejected for the reasons described above.

Q. Are you recommending any revisions to UNSG's cash working capital request?

A. Yes. The Company's attempt to revise the payment lag for gas purchases in a one-sided manner based on a post test year change should be rejected. Additionally, prior to testifying at the hearings, I would propose to update UNSG's cash working capital allowance to reflect the impact of RUCO's adjustments to operating expenses and revenue based taxes, and to synchronize the calculation of cash working capital with RUCO's recommended revenue increase.[14] I have reserved Schedule B-4 for a cash working capital update.

B-6 Accumulated Deferred Income Taxes

Q. What adjustment had you proposed to Accumulated Deferred Income Taxes ("ADIT") that were included in rate base by UNSG for Accounts 190 and 283?

A. In my direct testimony, as shown on Attachment RCS-2, Schedule B-6, I recommended that the following items reflected in Accounts 190 and 283 are removed:

- Dividend Equivalents
- Restricted Stock
- Restricted Stock - Directors
- Stock Options
- Vacation
- Pension

Each of these items has no corresponding liability that is offsetting rate base. The removal of these items decreases rate base by $423,669.

Q. Has UNSG objected to the removal of any of these ADIT items in its Rebuttal Testimony?

A. Yes. UNSG witness Kissinger opposes the adjustment for ADIT related to accrued pension and vacation liabilities because (1) such items were not removed in the prior

[14] Such synchronization has not yet been reflected at this time, but would be incorporated in a subsequent filing or in RUCO's brief.

UNSG rate case, and (2) such items "are calculated on an accrual basis and are a component of operating expense reflected in rates."[15]

Q. Does Ms. Kissinger admit that ADIT related to stock-based compensation was not allowed by the Commission as a component of rate base in UNSG's last rate case?

A. Yes, she indicates that the ADIT was disallowed because the underlying expense was disallowed, and in those circumstances the adjustment to ADIT is appropriate.[16]

Q. Have you recommended that the ADIT related to stock-based compensation be removed?

A. Yes.

Q. At page 3, Ms. Kissinger claims that removal of ADIT related to accrued pension and vacation liabilities "is another example of RUCO challenging accepted Commission-approved methods." Please respond.

A. Neither RUCO nor UNSG could identify where these items had been addressed in the prior cases cited in Ms. Kissinger's Rebuttal Testimony on page 3. UNSG's response to RUCO 11.25 states that:

> In the cases referenced on page 3 of the Rebuttal Testimony, there were no challenges of the inclusion of these items in rate base. Therefore, there was no need for the Commission to explicitly discuss these items in Decisions.

UNSG's response to RUCO 11.24 admits that:

> The Commission's method in addressing the amount of ADIT balance to be included in rate base is to review all of the testimony and briefs filed in each utility case and to decide the case based on the facts and evidence in that case.

[15] See, e.g., Kissinger rebuttal, page 3.
[16] See, Kissinger rebuttal, pages 3-4.

> The Commission's method is to consider the facts and evidence in light of its past practices and treatment of specific items in other cases with the same facts and evidence. By so doing, the Commission provides consistency of treatment among the ratepayers of Arizona.

Q. Do you agree with Ms. Kissinger's analysis of why an ADIT item should or shouldn't be included in rate base?

A. I agree that if an item is disallowed for ratemaking purpose, the related ADIT should also be removed. However, Ms. Kissinger's analysis would only focus upon ADIT in terms of operating expenses, and fails to recognize that there is a direct relationship between ADIT balances and other asset or liability accounts on a company's balance sheet. For example, as listed in UNSG's response to RUCO 11.21, the Company had balances of accrued vacation liability and accrued pension liability on its books at beginning and end of the test year, as listed there. The balances as of the June 30, 2008, the end of the test year are: $438,776 for the Accrued Vacation Liability and $1,732,676 for the Accrued Pension Liability. As such, these balances represent a source of non-investor supplied funds to the Company. Moreover, there is a direct relationship between the accrued liability amounts and the related amounts of ADIT for these items.

Q. How can non-investor supplied cost-free capital be reflected in the development of a utility's rate base?

A. Non-investor supplied cost-free capital, such as these accrued liabilities, could be reflected in the development of a utility's rate base in various ways, including (1) by adjusting the payment lags that are applied to the cash expenses in a lead-lag study or (2), by deducting the test year balances of the non-investor supplied capital from rate base.

Q. Did UNSG address the accrued vacation and accrued pension liability in its lead-lag study?

A. According to the response to RUCO 11.26(a), UNSG did not make any specific adjustments in its lead-lag study for Accrued Vacation Liability. UNSG's response to RUCO 11.26(b) states that the "UNS Gas Pension and Benefit lag reflects the payment lag for cash payments made to the pension funds trustees." Since the Accrued Pension Liability represents the liability for pensions that has not been funded, this amount was not covered by cash payments in the lead-lag study.

Q. Does UNSG have an accrued liability for stock-based compensation?

A. No.[17]

Q. How are debit-balance ADIT items generally related to a liability item on a company's balance sheet?

A. In general, debit-balance ADIT items (which appear as assets on a company's balance sheet) are related to a liability item on the Company's balance sheet in the following manner. The liability item multiplied by the income tax rate produces the related ADIT debit-balance. As an illustrative example, assume a $1 million accrued liability and a combined income tax rate of 38.6 percent. The debit-balance ADIT item related to the $1 million accrued liability would be $386,000, computed as follows: $1,000,000 x 38.6% = $386,000. There is typically a direct relationship between the ADIT item and the book-tax timing differences. In many instances, the ADIT is directly related to multiplying a liability (or deferred asset) balance by the income tax rate.

Q. How, specifically, is UNSG's balance of Accrued Vacation Liability related to the ADIT debit-balance item?

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[17] See, e.g., UNSG's responses to RUCO 11.21 (c) and 11.26(c).

A. As explained in UNSG's CONFIDENTIAL response to RUCO 11.22(a): [**BEGIN CONFIDENTIAL**] "

[**END CONFIDENTIAL**] The $169,367 is shown on Attachment RCS-2 to my direct testimony on Schedule B-6, line 8.

Q. How, specifically, is UNSG's balance of Accrued Pension Liability related to the ADIT debit-balance item?

A. The $1,045 ADIT debit balance item on Attachment RCS-2 to my direct testimony on Schedule B-6, line 12, was also computed by UNSG by multiplying a related adjusted liability amount by the combined income tax rate of 38.6 percent. Additional details for such calculation are presented on UNSG's CONFIDENTIAL response to RUCO 11.22(b). Thus, there is an adjusted accrued liability amount of $2,707 related to the ADIT amount of $1,045.

Q. As a result of UNSG's rebuttal testimony have you changed your recommendation about removing the ADIT items listed on Schedule B-6 that was filed with your direct testimony?

A. No. Those adjustments continue to be appropriate. The ADIT related to stock-based compensation should be removed because stock-based compensation should be disallowed for ratemaking purposes, as explained in my direct testimony.

The ADIT related to the Accrued Pension and Vacation Liabilities should be removed because the related Liability balances have not been used to reduce rate base.

Q. Do you have an alternative adjustment to rate base related to the Accrued Pension and Vacation Liability amounts and the ADIT related to those items?

A. Yes. If the ADIT debit-balance items related to the Accrued Pension and Vacation Liabilities of $1,045 and $169,367, respectively, are not removed from rate base, proper matching would require that the cost-free capital related to these ADIT balances in the form of the accrued liability amounts of $2,707 and $438,776 (basically the ADIT amounts divided by the combined income tax rate of 38.6%) should be deducted from rate base, for the net rate base reduction for these items of $271,069 as summarized in the following table:

Description	Adjusted Liability Amount	Combined Income Tax Rate	ADIT Debit Balance	Net Rate Base Impact
	(A)	(B)	(C)	(D) = A+B
Accrued Vacation Liability	$ (438,776)	38.60%	$ 169,369	$ (269,407)
Accrued Pension Liability	$ (2,707)	38.60%	$ 1,045	$ (1,662)
Total of these items	$ (441,483)		$ 170,414	$ (271,069)

IV. ADJUSTMENTS TO OPERATING INCOME

Q. What adjustments to operating income do you address in your Surrebuttal Testimony?

A. I address the following adjustments to operating income, which UNSG has disputed in its Rebuttal Testimony:

- Revenue Annualization
- Incentive Compensation Expense
- Stock Based Compensation Expense
- Supplemental Executive Retirement Plan Expense
- American Gas Association Dues Expense
- Outside Legal Expense
- Fleet Fuel Expense
- Rate Case Expense

- Payroll and Payroll Tax Expense
- Postage Expense

Revenue Annualization

Q. What is UNSG's rebuttal position on the customer annualization adjustment?

A. UNSG witness Bentley Erdwurm presents UNSG's arguments concerning the annualization adjustment. UNSG's rebuttal position is no different than its direct filing. The Company seeks to <u>reduce</u> test year revenue by approximately $516,000.

Q. Why do you disagree with UNSG's proposed customer annualization adjustment?

A. I disagree with UNSG's proposed customer annualization adjustment because it does not make sense to <u>reduce</u> test year revenue when UNSG has continued through the test year to experience year-over-year customer growth. Consequently, I have recommended that the test year revenue be used to set rates, without UNSG's proposed annualization adjustment. I set forth in detail in my direct testimony comparisons of UNSG's residential and commercial customer counts historically and through the test year. I also answered several UNSG data requests concerning the revenue annualization which further explain the rationale for rejecting UNSG's proposed adjustment to reduce test year revenue.

Q. How is a customer annualization typically used in a utility rate case?

A. Where a utility is growing and having to add plant during a test year to serve additional customers, a revenue annualization adjustment is typically employed in order to capture the impact on revenue from customer growth that has occurred and to better match the revenue with the test year plant that has been added to serve the new customers. The revenue growth that relates to the addition of customers is captured in an adjustment to increase revenue related to the increased plant which has been added to serve additional customers during the test year.

Q. How has the customer annualization been applied by UNS Gas in the current rate case?

A. While the Company employed an annualization method similar to the one that was used in its last rate case, the rote application of such method in the current case is <u>decreasing</u> test year revenues. Moreover, the decrease in revenue produced by the Company's calculation appears to be related to customer <u>seasonality</u> rather than a permanent decline in customer count during the test year, and therefore should not be adopted because it would understate test year and going-forward revenues.

Q. Hasn't UNS Gas experienced customer growth?

A. Yes, it has. Year after year, UNSG's number of average customers has been increasing. This holds true for the test year as well. Consequently, because customer counts year-over-year have been increasing for the past several years including the test year, test year revenues should not be decreased based on the misapplication of an annualization adjustment. In other words, while the application of an annualization adjustment may have made sense and been appropriate in UNSG's last rate case to account for customer growth that had occurred during that test year which ended December 31, 2005, rote application of such a method in the current case produces results that do not make sense because it essentially assumes that UNSG is losing residential and commercial customers, when clearly that is NOT the case.

UNS Gas has added, on average, both residential and commercial customers in each and every year, including the test year. Consequently, an adjustment to <u>decrease</u> test year revenue would be inappropriate by understating test year and going-forward revenues and should be rejected. Test year revenue of $516,000 should not be removed as proposed by UNSG. RUCO adjustment C-1 filed with my Direct Testimony restores this amount of actual test year revenue to the test year.

Incentive Compensation Expense

Q. What is the basis for UNSG's disagreement with the adjustment to remove 50 percent of the incentive compensation expense?

A. UNSG witness Dukes' Rebuttal Testimony at pages 11-16 addresses this. Basically, UNSG disagrees with the evaluation of who benefits from incentive compensation that has been employed by the Commission in a series of recent decisions on this issue. Mr. Dukes' Rebuttal Testimony generally reiterates arguments that have been considered and rejected by the Commission in prior cases, including the most recent rate cases involving UNSG and its affiliate, UNS Electric.

Q. Please explain why a 50 percent allocation to shareholders is appropriate for an incentive compensation program.

A. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50% of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

Q. What are the key provisions of the incentive compensation program?

A. The Company's response to Staff data request TF 6.64 states that UNS Gas non-union employees participate in UniSource Energy Corporation's ("UniSource") Performance Enhancement Plan ("PEP"). The structure of the PEP determines eligibility for certain bonus levels by measuring UniSource's performance in three areas: (1) financial performance; (2) operational cost containment; and (3) core business and customer service goals. Levels of achievement in each area are assigned percentage-based "scores." Those scores are combined to calculate the final payout level. The amount made available for bonuses pursuant to the PEP may range from 15 to 150 percent of the targeted payout level. The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent.

As explained in the Company's response to Staff data request TF 6.64:

> The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 3% to 14% for regular unclassified employees, and 25% to 80% for Managers and Officers. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion, based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Q. Is UNSG's proposed treatment of incentive compensation expense a conscious deviation from principles and policies established in prior Commission Orders?

A. Yes. Data request TF 6.103 asked[18]:

> Are there any aspects of the Company's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and policies established in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain the Company's perception of the principle

[18] See Attachment RCS-5 of my direct testimony.

> established in the prior Commission orders, how the Company's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

UNSG's response to this data request states in part that: "In the prior Commission decision, 50% of the incentive compensation expense was excluded from revenue requirements. UNS Gas is requesting full recovery of the normal and recurring level of incentive compensations expense."

Q. What criteria has the Commission found important in deciding issues concerning utility incentive compensation in recent cases?

A. The criteria the Commission has found important in deciding this issue in recent cases are described in various orders which have addressed the treatment of utility incentive compensation expense for ratemaking purposes. In Decision No. 68487 (February 23, 2006), the Commission adopted Staff's recommendation for an equal sharing of costs associated with the Southwest Gas Corporation's ("SWG") Management Incentive Plan ("MIP") expense. For example, in reaching its conclusion regarding SWG's MIP, the Commission stated in part on page 18 of Order 68487 that:

> We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendations to be a reasonable resolution.

Mr. Dukes has not refuted the fact that both shareholders and ratepayers derive some benefit from incentive goals.

Q. Do UNSG's shareholders and customers both benefit from the achievement of incentive compensation program?

A. Yes. Shareholders benefit from the achievement of financial goals. Additionally, shareholders benefit from the achievement of expense reduction and expense containment goals between rate cases. Shareholders and ratepayers can both benefit from the achievement of customer service goals.

Q. Have the facts changed materially since the last UNS Gas rate case that a different result concerning the sharing of incentive compensation expense should occur?

A. No, I don't believe so. The rationale for the 50 percent allocation to shareholders of this expense in the current case appears to be consistent with the Commission's findings concerning SWG's MIP in Decision No. 68487, and findings about UNSG's incentive compensation expense in Decision No. 70011. In Decision No. 70011 (November 27, 2007), in the last UNS Gas rate case, Docket No. G-04204-06-0463 et al, the Commission stated in part on page 27 that:

> We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.

Q. At page 12 of his Rebuttal Testimony, Mr. Dukes claims that Decision No. 69663 supports the UNSG position. Wasn't an equal sharing of incentive compensation expense ordered in other more recent Commission decisions in rate cases involving Arizona utilities?

A. Yes. In Decision No. 70360 (May 27, 2008), in the recent UNS Electric, Inc. rate case, Docket No. E-04204A-06-0783, the Commission stated at page 21 that:

> Consistent with our finding in the UNS Gas rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a

> reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program...Given that the arguments raised in the UNS Gas case are virtually identical to those presented in this case, we see no reason to deviate from that recent decision.

Finally, in Decision No. 70665 (December 24, 2008), in the most recent Southwest Gas Company rate case, Docket No. G-01551A-07-0504, the Commission stated at page 16 that:

> In the last Southwest Gas rate case, as well as several subsequent cases,[3] we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated:
>
>> In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.
>
> (Id.) We believe the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs.[4]
>
> [3]See UNS Gas, Inc., Decision No. 70011 (November 27, 2007) at 27; Arizona Public Service Co., Decision No. 69663 (June 28, 2007) at 27; and UNS Electric, Inc., Decision No. 70360 (May 27, 2008) at 21.
>
> [4]On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ("SIP"). The costs related to similar incentive plans were recently rejected for APS and UNS Electric. (See Ex. S-12 at 32-34.) As was noted in the APS case, stock performance incentive goals have the potential to negatively affect customer

> service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price. (Decision No. 69663 at 36.)

Q. Should the 50/50 ratepayer/shareholder sharing that the Commission applied to utility incentive compensation in UNSG's last rate case be modified to a 100 percent ratepayer responsibility for such cost based on the analysis presented by Mr. Dukes?

A. No. The 50/50 sharing of UNSG's incentive compensation program cost ordered by the Commission in Decision No. 70011 should continue to apply in the current UNSG rate case.

Q. Given the current economic conditions, have you seen other utilities volunteering to remove certain compensation from their test year expenses?

A. Yes. I have been seeing increasing examples of this recently where utilities are agreeing to remove discretionary expenses such as incentive compensation, executive raises, SERP, and other expenses, in recognition of the bad economy. As an illustrative example, testimony filed by PEPCO in a D.C. PSC rate case in May 2009, included the following:

- "... the Company has decided to eliminate the 2009 merit increases for its executives and its other non-union management employees."[19]
- "Adjustment 5 excludes from cost of service the costs associated with non-qualified executive retirement plans, as ordered by the Commission in Form Case No. 939 (Order No. 10646, page 128).[20]
- "As noted by Company Witness Kamerick, there will be no adjustment to non-union wages beyond the annualization of the March 1, 2008 increase."[21]
- "Adjustment 22 reflects the exclusion of incentive plan payments in accordance with the Commission's decision in Formal Case No. 1053."[22]

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[19] PEPCO witness A.J. Kamerick Direct Testimony (May 2009), page 29, DCPSC Case No. 1076.
[20] PEPCO witness Linda J. Hook Direct Testimony, page 9.
[21] Id at page 13.
[22] Id at page15.

Q. Please summarize your recommendation concerning UNSG's incentive compensation expense.

A. I recommend continuing the 50 percent allocation for UNSG's incentive compensation expense to shareholders ordered by the Commission in Decision No. 70011. This results in a reduction to test year expense of $140,484.

Stock-Based Compensation Expense

Q. What does UNSG claim in its Rebuttal Testimony concerning stock-based compensation expense?

A. UNSG witness Dukes addresses stock based compensation expense at pages 16-17 of his testimony. At page 17, he claims that: "Neither Staff nor RUCO has questioned that the program provides benefits to customers, its prudency, the reasonableness of the cost or that it was incurred to provide service to customers." This statement by Mr. Dukes does not appear to be consistent with the analysis presented in my Direct Testimony. In fact, RUCO is questioning how UNSG's stock-based compensation expense benefits customers and the reasonableness of the additional cost. In fact, especially in view of the poor economic conditions, it would be highly unreasonable to charge UNSG's stock-based compensation expense to ratepayers in the current UNSG rate case. The removal of stock-based compensation expense is consistent with a number of recent Commission decisions that have addressed this issue.

Q. For what types of stock-based compensation has UNSG included an expense in the test year?

A. UNSG has included an expense in the test year for the following types of stock-based compensation:

- Stock Option Expense
- Dividend Equivalents on Stock Units
- Performance Stock Award
- Dividend Equivalent on Stock Options
- Directors Stock Awards

My direct testimony discussed each of these programs.

Q. Did the Commission recently disallow another utility's stock based compensation in a recent decision?

A. Yes. In Decision No. 69663, from a recent APS rate case, the Commission adopted a Staff recommendation where cash-based incentive compensation expense was allowed and stock-based compensation was disallowed. Additionally, page 36 of Decision No. 69663 indicates that the Commission rejected an argument by APS that the Commission not look at how compensation is determined or its individual components:

> "APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost."
>
> "We agree with Staff that APS' stock-based incentive compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate. As

> testified to by Staff witness Dittmer and set out in Staff's Initial brief, "[e]nhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. ... For example, some maintenance can be temporarily deferred, thereby boosting earnings. ... But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." [cite omitted] To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation."

Thus, in Decision No. 69663, the Commission made an adjustment to disallow a portion of that utility's incentive compensation expense, specifically the stock-based compensation.

Q. Was stock-based compensation expense also disallowed in the Commission's recent decision in the rate case involving UNS Electric, Inc.?

A. Yes, it was. In Decision No. 70360 at page 22, the Commission, in referencing a similar decision regarding Southwest Gas Corporation as well as APS' last rate case stated:

> "For these same reasons, we agree with Staff that test year expenses should be reduced to remove stock-based compensation to officers and employees...The disallowance of stock-based compensation is consistent with the most recent rate case for Arizona Public Service Company (Decision No. 69663)."

Q. Please discuss the reasons for removing stock-based compensation.

A. Ratepayers should not be required to pay executive compensation that is based on the performance of the Company's (or its parent company's) stock price. Additionally, prior to being required to expense stock options for financial reporting purposes under Statement of Financial Accounting Standards No. 123 Revised (SFAS 123R), the cost of stock options was typically treated as a dilution of shareholders' investments, i.e., it was a cost borne by shareholders. While SFAS 123R now requires stock option cost to be expensed on a company's financial statements, this does not provide a reason for shifting the cost responsibility for stock options from shareholders to utility ratepayers.

Q. Does the poor economic condition present another reason for removing stock-based compensation?

A. Yes. While I believe that UNSG's stock based compensation expense should be removed, even if the economic conditions were better, the current poor economic conditions are causing hardship for customers in many ways, not just related to higher utility rates, and present another reason at this time for removing this expense. In fact, some other utilities have been responding to the poor economic conditions by removing elements of compensation expense from their rate increase request filings. UNSG has taken the opposite approach and continues to litigate such issues. In view of the poor economy, this would be a particularly bad time for the Commission to change from its historical perspective and charge UNSG's ratepayers for stock-based compensation expense.

Q. Please summarize your recommendation.

A. As shown on Attachment RCS-2, Schedule C-4, which was filed with my Direct Testimony, an adjustment should be made to decrease test year expense by $266,399 to reflect the removal of UNSG's stock option compensation expense that is allocated to Arizona operations. The expense of providing stock options and other stock-based compensation to officers, employees and directors beyond their other compensation should be borne by shareholders and not by ratepayers.

Supplemental Executive Retirement Plan Expense

Q. Despite a series of Commission decisions disallowing SERP and the bad economy, is USNG continuing to argue for charging ratepayers for SERP expense?

A. Yes. UNSG witness Dukes' Rebuttal Testimony at pages 17-19 presents essentially the same arguments that were previously presented by this company in its last rate case and by its affiliate, UNS Electric, in its respective last rate case for Supplemental Executive Retirement Plan ("SERP"). There does not appear to be anything new in UNSG's arguments. Such arguments have been previously heard and rejected by the Commission in a series of rate case decisions on utility SERP issues.

Q. At page 18, UNSG witness Dukes claims that SERP is not an excess benefit. What is SERP?

A. The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. How has utility SERP expense been disallowed by the Commission in a series of recent rate cases?

A. To my knowledge, utility SERP expense has been consistently disallowed by the Commission in recent decisions. In Decision No. 68487, February 23, 2006, in a Southwest Gas Corporation rate case, the Commission adopted a recommendation by

RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Order 68487 that:

> Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

Q. Was SERP expense disallowed in the Commission's decision in the last rate case involving UNS Gas, Inc?

A. Yes, it was. See Decision No. 70011 at pages 27-29. Notably, at page 28 of that Decision, the Commission stated:

> … the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case [See also Arizona Public Service Co., Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were excluded in their entirety.], and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

Q. Was SERP expense also disallowed in the Commission's recent decisions in the rate cases involving UNS Electric, Inc.?

A. Yes, it was. In the recent UNS Electric, Inc. rate case, in Decision No. 70360 at page 22, referencing the above captioned quote, the Commission stated:

> We see no reason to depart from the rationale on this issue in the most recent UNS Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

The Commission's Decision No. 70665 (December 24, 2008) in the most recent Southwest Gas rate case, Docket No. G-01551A-07-0504, stated as follows on pages 17-18:

> We agree with Staff and RUCO that the SERP expenses sought by Southwest Gas should once again be disallowed. We do not believe any material factual difference exists in this case that would require a result that differs from the Company's prior case. In that case, we stated:
>
>> [W]e believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.
>
> (Decision No. 68487 at 19.)
>
> In the recent UNS Gas, APS, and UNS Electric cases, we followed the rationale cited above in disallowing SERP expenses. In Decision No. 70011, we indicated that SERP costs should not be recoverable and indicated:
>
>> [T]he issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of

> executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.
>
> [Id. At 28, (footnote omitted).] For these reasons, we agree with the recommendations of Staff and RUCO that the request for inclusion in rates of SERP expenses should be denied. We therefore adopt the recommendations of Staff and RUCO on this issue.

Q. How do the prevailing poor economic conditions affect your analysis of SERP expense?

A. I believe that UNSG's SERP expense should be disallowed for the reasons stated above, even if the economic conditions were better. However, the current poor economic climate represents an additional reason for disallowing this expense. As I have noted elsewhere in my surrebuttal testimony, in view of the poor economy, other utilities have been responding by removing elements of compensation expense. This would be a particularly bad time, therefore, to start charging UNSG ratepayers for an executive compensation expense that has recently been excluded from rates.

Q. Please summarize your recommendation concerning UNSG's SERP expense?

A. I recommend removing UNSG's expense for the SERP.

American Gas Association Dues

Q. Why does UNSG object to a proposed adjustment for American Gas Association dues?

A. This is addressed at UNSG witness Dukes' Rebuttal Testimony at page 21. He opposes the recommended adjustment on the following grounds: (1) Staff did not make the adjustment, and (2) he claims that RUCO adjustment "is based on a 2001 NARUC study that is based on 1999 data" that Mr. Dukes claims is stale and not relevant.

Q. Why didn't Staff make a larger adjustment for AGA dues in the current UNSG rate case?

A. That is not clear.

Q. Did the Commission make a similar adjustment for AGA dues in the most recent Southwest Gas Corporation rate case?

A. Yes. In the most recent Southwest Gas Corporation rate case, I was a witness for Staff and I did recommend a similar adjustment to Southwest's AGA dues, which was adopted by the Commission in Decision No. 70665. The adjustment to UNSG's AGA dues is highly similar to the one adopted by the Commission in Decision No. 70665 and reduces test year expense by $18,678 to reflect the removal of 40 percent of AGA dues. In the current UNSG rate case, I have also recommended the removal of 40 percent of AGA core dues, while UNSG's filing reflected the removal of only 4 percent of the AGA dues.

Q. Is only a 4 percent disallowance of AGA dues-funded activities adequate?

A. No. UNS Gas has demonstrated that there is some benefit of AGA membership to the Company and to Arizona ratepayers from some of the AGA's functions. However, the Company has failed to demonstrate that ratepayers should fund activities conducted through an industry organization that would be subject to disallowance if conducted directly by the utility. The Company has failed to demonstrate that a disallowance of AGA dues of only 4 percent is adequate. As I discussed in my Direct Testimony, other states have used a significantly higher disallowance percentage for gas utility AGA dues than UNSG is proposing here. Moreover, a 40 percent disallowance is consistent with the categories of AGA dues established by NARUC, and with the Commission's recent Decision No. 70665 in a Southwest Gas rate case.

Q. In determining the 40 percent disallowance for AGA dues did you rely only on a 2001 NARUC study?

A. No. I relied not only upon information in the two most recent National Association of Utility Regulatory Commissioners (NARUC) sponsored Audit Reports of the Expenditures of the American Gas Association, but also utilized an analysis of the components by function of the AGA's 2007 and 2008 budgets. I also relied upon a Florida PSC Staff memorandum, discussed in my direct testimony, which contained a 40 percent AGA dues disallowance. I have previously presented copies of relevant pages from the NARUC-sponsored audit reports which were provided in Attachment RCS-4. Additionally, AGA 2007 and 2008 budget information, by component, was summarized in my Direct Testimony filing on Attachment RCS-2, Schedule C-6, page 2.

Q. What is the purpose of the NARUC-sponsored audits of AGA expenditures?

A. The purpose of the NARUC-sponsored audits of AGA expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. As stated in the June 2001 memo to the Chairs and Chief Accountants of the State Regulatory Commissions included with the NARUC-sponsored audit of 1999 AGA expenditures: "Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities." The NARUC-sponsored audit categorizes the AGA expenditures and, as stated in the aforementioned memo, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit."

Q. How did the Commission address the issue of the appropriate portion of AGA dues to disallow for ratemaking purposes in the most recent Southwest Gas Corporation rate case?

A. The Commission adopted a 40 percent disallowance of AGA dues in Decision No. 70665, in the recent Southwest Gas rate case. In Docket No. G-01551A-07-0504, the Commission adopted Staff's recommendation to disallow 40% of AGA dues. Decision No. 70665, at page 12 stated that:

> We find that Staff's recommended disallowance of 40 percent of AGA dues represents a reasonable approximation of the amount for which ratepayers receive no supportable benefit.

Q. What amount of UNSG's AGA membership dues expense should be removed from test year expense?

A. I recommend that 40 percent, or $18,678, from the $46,694 of test year expense for AGA membership dues be removed, consistent with the analysis described in my Direct Testimony and above, and consistent with Decision No. 70665. This removes $16,762 more than UNSG's proposed 4 percent removal which amounted to $1,915.

Outside Legal Expense

Q. What is the test year amount of Outside Legal Expense?

A. The Company's test year expense for Outside Legal Expense (other than rate cases) is $83,555. The Company has made a *pro forma* adjustment to increase Outside Legal Expense by $305,984 to "normalize" this expense in the test year, based on a three year average of 2005 - 2007 expenses, which included large annual legal costs related to an El Paso Natural Gas ("EPNG") pipeline case before the FERC.

Q. What is the basic dispute over the amount of Outside Legal Expense?

A. On behalf of RUCO I have recommended an adjustment to remove a portion of UNS Gas' significant *pro forma* <u>increase</u> amount for normalizing outside legal expense in the test year. UNSG witness Dukes' addresses this at pages 27-28 of his Rebuttal Testimony. Mr. Dukes claims at page 27 that: "Both Staff and RUCO fail to provide an allowance for normalized, on-going costs of legal services, based on either historical or projected costs." At page 28, he cites the Commission's Decision No. 70011 in the last UNSG rate case, which allowed UNSG to recover outside legal expenses related to FERC rate cases.

Q. Describe UNS Gas' historical Outside Legal Expenses.

A. The Company spent $488,000, $439,000, and $242,000 in the years 2005, 2006, and 2007 on outside legal costs for matters other than ACC rate cases. A significant amount of these fees in those years are related to the EPNG regulatory proceedings before the FERC, which had settled. The Company's outside legal fees have steadily declined since its last rate case.

Q. Should a backward looking average be used to establish a normalized amount of Outside Legal Expenses in the current UNSG rate case?

A. No, because circumstances have changed. As noted above, UNSG's outside legal expenses have decreased. In Decision No. 70011 (November 27, 2007), the Commission stated (at page 20) that "We believe that the Company's allowable legal expenses should be set at a level that reflects more accurately its actual experience, both historical and anticipated." I generally agree with this statement, but am specifically concerned that it not be transformed into a recipe for charging ratepayers prospectively for abnormally high levels of legal expense incurred by a utility in years prior to the test year; consequently, RUCO generally agrees with the principle of allowing for a normalized and reasonable level of legal expense, but cautions against transforming this principle into a means for retroactive recovery by a utility of its past year's legal costs, particularly in years when such costs may have been abnormally high.

Q. In what FERC proceedings has UNSG participated?

A. A listing of the FERC proceedings in which UNSG has participated was provided in response to UNSG's CONFIDENTIAL response to RUCO 11.11.

Q. Has UNSG demonstrated that its outside legal expense has been cost-effective?

A. No. In response to data request RUCO 11.6, RUCO 11.11(g) and others, UNSG has indicated that it does not have any analysis on the impact of its participation in any of the FERC proceedings.

Q. At page 28 of his rebuttal testimony, Mr. Dukes refers to a current El Paso Natural Gas system wide rate case at FERC, Docket No. RP08-426. Does UNSG have a budget for costs related to that docket?

A. UNSG was asked about this in data request RUCO 11.5a. UNSG's CONFIDENTIAL response states that: [**BEGIN CONFIDENTIAL**] [**END CONFIDENTIAL**]

Q. Has UNSG provided additional information about that El Paso Natural Gas system wide rate case at FERC?

A. Yes. UNSG's CONFIDENTIAL response to RUCO 11.5 provides some additional information on FERC Docket No. RP08-426.[23]

Q. Are any of UNSG's affiliates also customers of El Paso Natural Gas and/or are intervening in FERC Docket No. RP08-426?

A. Yes. UNSG's CONFIDENTIAL response to RUCO 11.5(k) states that: [**BEGIN CONFIDENTIAL**]

[**END CONFIDENTIAL**]

Q. How are costs of participating in FERC Docket No. RP08-426 being allocated among UNSG and its affiliates?

[23] UNSG's response to RUCO 11.5, without voluminous attachments, is included in Attachment RCS-9 to my Surrebuttal Testimony.

A. UNSG's CONFIDENTIAL response to RUCO 11.5(m) states that: [**BEGIN CONFIDENTIAL

[**END CONFIDENTIAL**]

Q. Was the cost of participating in the last El Paso Natural Gas case allocated among UNSG and its affiliates?

A. According to the response to RUCO 11.8, apparently there was no apportionment of the cost of participating in the last EPNG FERC rate case. UNSG's response to RUCO 11.8 states that: "In its last rate case, FERC Docket NO. 95-363, EPNG filed its Settlement Proposal on December 6, 2007. FERC issued its order accepting the Settlement Proposal on August 31, 2007. TEP did not become a customer of EPNG until April 2007; therefore, TEP did not participate in the rate case." In response to RUCO 11.8(b), which had asked about the apportionment of the cost of participating in the FERC case among each of UNSG's affiliates, UNSG responded: "N/A." Consequently, none of the cost to UNSG from participating in the last EPNG FERC rate case was apportioned to other affiliates, such as TEP; however, in the future, there would be a [**BEGIN CONFIDENTIAL**]

[**END CONFIDENTIAL**] as described in the response to RUCO 11.5(m). This is a significant change in circumstances, and should warrant not using UNSG's prior year FERC related costs as the basis for setting a "normal" level in the current case, at minimum, without some significant discounting of such past costs to reflect the fact that

UNSG did not share such costs with its affiliates in the past, but would be doing so on a going-forward basis.

Q. At page 28 of his Rebuttal Testimony, Mr. Dukes mentions that Transwestern is expected to file for a system-wide rate case at FERC in 2011. Do you have any other information about that anticipated filing?

A. Yes. UNSG's response to RUCO 11.35(d) indicates that [**BEGIN CONFIDENTIAL**]

[**END CONFIDENTIAL**]

Q. Has UNSG provided its budgets for "Outside Legal Services"?

A. Not to the extent requested. UNSG's response to RUCO 11.35(b) and (c) state, respectively that: [**BEGIN CONFIDENTIAL**]

[**END CONFIDENTIAL**]

Q. What amount of outside legal expense are you recommending?

A. Based on a review of the additional material provided by UNSG in response to RUCO set 11, I recommend that if the Commission is inclined to give UNSG more money for outside legal expense, that it not base the amount on a mere average of historical expenditure levels because circumstances have changed and UNSG's budget for outside legal has decreased. The amount allowed in this case should in no event be higher than UNSG's 2009 budget, which was provided in the CONFIDENTIAL response to RUCO 11.35. In my direct testimony I had recommended an allowance of $171,865. Because it appears that some level of EPNG FERC costs will be ongoing, I had provided for an annual amount for EPNG FERC proceedings of approximately $100,000 based on actual test year costs. As shown on Schedule C-7, this adjustment had reduced UNSG's requested outside legal expense by $217,674. The annual amount of $171,865 of normalized outside legal expense that I had recommended in my direct testimony should be adequate in view of the fact that future FERC costs will be allocated between UNSG and TEP. Moreover, UNSG has not presented a cost-benefit analysis, or an evaluation of the impact of its legal expenditures.

Fleet Fuel Expense

Q. What is the dispute concerning Fleet Fuel Expense?

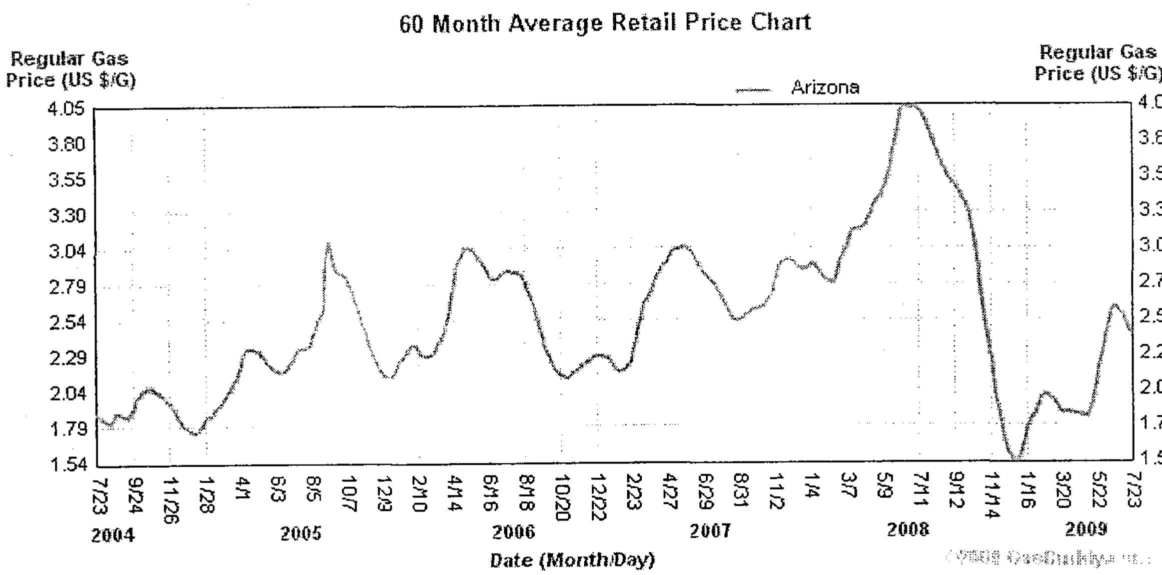
A. UNSG witness Dukes addresses this at pages 29-31 of his Rebuttal Testimony. All parties – UNSG, Staff and RUCO – appear to agree that the test year level of expense needs to be adjusted to a "normal" level given the extreme volatility of fuel expense; however, the parties do not agree upon the amount of adjustment. My reasons for recommending a normalizing adjustment include that the test year fleet fuel expense was based on unusually high fuel prices in effect during the test year, in some months over $4.00 a gallon, the country's record high point. The amount of gallons purchased in the test year is also the highest among historical yearly gallons purchased.

Mr. Dukes appears to agree with the use of a three-year average of fuel usage to normalize the expense. However, he wants to apply a backward-looking cost of fuel that includes the extreme peak costs during 2008 in order to normalize the cost.

At page 30, Mr. Dukes also identifies two technical corrections to the adjustment calculation I had presented with my direct testimony: (1) remove an additional amount inadvertently included and (2) reflect an O&M expense allocation of 73.4 percent. I agree with Mr. Dukes about these two points and will reflect appropriate corrections.

Q. Do you agree with the concept of using an average for fuel prices?

A. Yes. Because the cost has been so volatile, using an average is appropriate to derive a normalized amount. However, I do not agree with Mr. Dukes that a backward-looking average of 2006-2008 prices is necessarily representative of current and expected prices. Based on the following chart, gasoline prices in Arizona reached extreme levels in 2008, over $4 per gallon, and have been significantly lower before and since.



Q. In response to RUCO discovery, did UNSG provide more current information on Fleet Fuel Expense?

A. Yes. In response to RUCO 11.36(f), UNSG provided average fuel prices for the 36-months through June 2009.

Q. Have you updated RUCO's adjustment for Fleet Fuel Expense?

A. Yes. Attachment RCS-7, Schedule C-8 Revised shows the updated adjustment. This adjustment uses an average fuel cost of $2.95 per gallon based on January 2006 through June 2009 information. The incorporation of more current information and a longer period helps mitigate the impact of the extreme peak gasoline prices of mid-2008. This average cost of fuel also is reasonable in view of the graph of historic Arizona gasoline prices from ArizonaGasPrices.com depicted on the above chart. As shown on Schedule C-8 Revised, page 1 of 3, I have reduced fleet fuel expense by $71,963. This exceeds the $51,258 reduction proposed by UNSG in its Rebuttal Testimony by $20,705.

Q. What is shown on Schedule C-8 Revised, pages 2 and 3?

A. Schedule C-8 Revised, page 2, shows the monthly Fleet Fuel Expense, including cost per gallon for January 2006 through June 2009, based on information provided by UNSG in response to data requests RUCO 10.1 and 11.36. Schedule C-8 Revised, page 2, shows the allocation of the adjustment for Fleet Fuel Expense proposed in UNSG's Rebuttal Testimony and RUCO's recommendation, and the difference, by FERC account.

Rate Case Expense

Q. What amount of rate case expense is the Company requesting recovery for in this case?

A. UNS Gas is requesting recovery of $500,000 for current rate case expenses over three years for an annual allowance of $166,667 per year. Mr. Dukes' Rebuttal Testimony at page 19 indicates that the Company expects to incur more than that, inclusive of the substantial TEP employee time charged for UNSG rate case cost and outside counsel. UNSG has agreed with an adjustment to remove an amortization of $100,000 of unamortized rate case expense from the prior rate case and proposed that it should also be normalized over three years for an additional amount of $33,333, which brought the Company's request for *pro forma* total rate case expense to $200,000 per year. The Company stated in response to Staff data request TF 6.68 that it did <u>not</u> remove amortization of rate case expense related to the previous rate case that will be recovered prior to new rates becoming effective. Therefore, the Company's test year amount of rate case expense included an additional $58,333. The response to TF 6.68 also states that this amount would be removed resulting in a reduction of test year rate case expense of $58,333.

Q. Do you agree with the Company's proposed amount of rate case expense for this case of $500,000?

A. No. Even with the Company's proposed correction, the total amount of rate case expense is excessive and would represent an unreasonable burden on ratepayers. Additionally, the amount included in rates for an allowance for rate case expense should be understood to be a normalized amount, not an amortization.

Q. What total amount of rate case expense was allowed in the last UNSG rate case?

A. The allowance for rate case expense was based on a total amount of $300,000 for rate case expenses in its prior rate case, Docket No. G-04204A-06-0463, normalized over a period of three years.

Q. How does the current UNSG rate case compare with the last UNSG rate case?

A. The current UNS Gas rate case is similar to and presents many of the same issues and adjustments to rate base and operating expenses (i.e., CWIP, property taxes, incentive compensation, etc.), if not less, than those that were addressed by the Commission in the Company's last rate case. For example, in the prior rate case, it was the Company's first case under its new ownership. The Company also conducted a depreciation study supporting new depreciation rates in the prior case. UNS Gas is not proposing to revise its depreciation rates in this case.

Q. What do you recommend for the allowance for rate case expense for UNS Gas in this proceeding?

A. I recommend an annual allowance of $100,000, based on normalizing a total amount of $300,000 over a three-year period. The $500,000 for current rate case cost requested by UNS Gas is nearly double (i.e., is almost 81 percent higher) the amount of rate case expense requested and allowed by the Commission in the Southwest Gas' last rate case, Docket No. G-01551A-07-0504, which was $276,000 in total and was normalized over a three-year period, to produce an annual allowance of $92,000 per year. The rate case expense allowance in the last UNS Gas case was $100,000, based on normalizing a total amount of $300,000 over three years.

Q. How does your recommended allowance for rate case expense for UNS Gas in this proceeding compare with the allowed rate case expense for UNSG's affiliate, UNS Electric, in that utility's last Arizona base rate case?

A. The rate case allowance in the last UNS Electric rate case was $100,000, based on normalizing a total amount of $300,000 over three years. My recommended allowance for UNSG is comparable to the Commission's allowance for rate case cost in the last UNS Electric rate case.

Q. How does the current UNS Gas rate case proceeding compare with range of issues for UNSG in its last rate case and for and UNSG's affiliate, UNS Electric, in that utility's last Arizona base rate case?

A. The current UNS Gas rate case has similarities to the last UNS Gas and UNS Electric rate cases in terms of both the scope of issues in the cases, and the majority of each application being sponsored by in-house or affiliated company staff.

Q. Please summarize your recommended adjustment.

A. I recommend an annual allowance of $100,000 per year, based on a total of $300,000 normalized over three years. Schedule C-9 filed in Attachment RCS-2 with my direct testimony reduces the Company's proposed annual allowance for current rate case costs by $100,000.

I also recommend that the amount recorded by UNS Gas in the test year of $58,333 for prior rate case expense be removed. The Company's response to Staff data request TF 6.68 indicates this adjustment is needed to correct an error in UNS Gas' filing.

As shown on Schedule C-9, my total adjustment allows for a $100,000 per year normalized rate case expense, and reduces the rate case expense in UNSG's filing by $158,333.

2010 Pay Increase

Q. What does UNSG's Rebuttal Testimony dispute about your recommended disallowance of a projected 2010 pay increase?

A. UNSG witness Dukes addresses this issue at pages 9-10 of his Rebuttal Testimony. Mr. Dukes disagrees with this adjustment because: (1) Staff did not object to the Company's payroll adjustments in Staff's direct testimony; (2) the argument that the adjustment is too far outside of the test year was made by RUCO in prior Southwest Gas cases and was rejected by the Commission; (3) there is no mis-match with the test year that ended June 30, 2008 because the new rates are not likely to go into effect until January 2010, and the increase is attributable to the current work force. As to the non-union increase, Mr. Dukes claims that "the increase will be known prior to rates going into effect and support of the approved increase can be provided prior to the close of the record."[24]

Q. Please respond to Mr. Dukes' rebuttal on this issue.

A. I acknowledge that in prior Southwest Gas rate cases, the Commission has allowed a second round of beyond the test year rate increases. Additionally, I agree with Mr. Dukes that it appears that Staff's direct filing made no adjustment to remove or adjust the projected January 2010 pay increase.

The projected increase for January 2010 particularly for non-union employees, however, is not known or certain at this time. That amounts to $96,088, per UNSG's response to RUCO 11.40(b).

Moreover, I have seen other utilities curtailing projected wage increases and cutting back compensation and benefits in response to the poor economy. Additionally, the economic climate in Arizona in mid-2009 is worse than it was in each of the last Southwest Gas filings, as UNSG admits in its response to RUCO 11.40(e). Consequently, I believe there may be compelling circumstances in the context of the current UNSG rate case, including the poor economic climate, that did not exist in the context of the prior Southwest Gas cases, and which may warrant a different treatment of estimated future pay increases that would occur more than one year beyond the test year.

Q. Please elaborate on how some other utilities have responded to the poor economic climate by addressing payroll and benefits.

[24] Dukes Rebuttal Testimony, page 10, lines 13-15.

A. In a current rate filing in Vermont, Green Mountain Power has limited the increases in compensation to the contractual rate for bargaining employees and has frozen wages for non-bargaining employees. Potomac Electric Power Company ("PEPCO") in its current filing in Washington D.C. PSC Case No. 1076 has indicated that there will be no wage increase for non-bargaining employees in 2009, thus there is no adjustment to non-union wages in its filing beyond the annualization of a March 1, 2008 increase. Additionally, PEPCO included a 1.5 percent July 1, 2009 increase for union wages, even though the annual contractual increase for the past several years had been 3 percent. Peoples Gas System in Florida PSC Docket No. 080318-GU eliminated the executive increase and reduced the employees' compensation increases.

Q. Please summarize your recommendation concerning the January 2010 pay increase.

A. I recommend that the Commission remove this expense and the related payroll tax expense for the reasons described in my Direct Testimony and above.

Postage Increase

Q. Page 31 of UNSG witness Dukes' Rebuttal Testimony addresses a postage adjustment proposed by Staff. Do you agree that an adjustment should be made for a known and measurable increase in postage rates that has occurred?

A. Yes, and the amount of such adjustment should be appropriately coordinated with the test year number of customers. As explained above, I have disagreed with UNSG's proposal to decrease test year revenue for a customer annualization adjustment. Consequently, my test year recommendations reflect the actual test year customers, not the reduced level advocated by UNSG. Consequently, the postage adjustment consistent with RUCO's filing is slightly higher than as proposed by UNSG. As shown on Attachment RCS-7, Schedule C-13, the impact of the 2 cent postage rate increase on the unadjusted test year customer billings is $34,782. This amount exceeds the $12,750 postage adjustment in UNSG's direct filing by $22,031.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

UNS GAS, INC.
FLEET FUEL EXPENSE
Updated Adjustment

Docket No. G-04204A-08-0571
Attachment RCS-7
Schedule C-8 Revised

Line No.	Description	2006 (A)	2007 (B)	2008 (C)	YTD June 2009 (D)	Normalized Based Upon Average (E)	Test Yr. (F)	Pro Forma Fuel Adjustment (G)
	I. Per UNSG Rebuttal							
1	Gallons	221,734	228,106	221,120		**223,653**	228,369	
2	Miles Driven	3,607,551	3,607,551	2,314,954		**3,176,685**	2,960,186	
3	Fuel Cost	$608,781	$664,365	$779,691		**$684,279**	$753,931	
4	Cost per Gallon	$2.73	$2.92	$3.50		**$3.06**	$3.30	
5	Percentage Allocated to O&M	73.4%	73.4%	73.4%		**73.4%**	73.4%	
6	**Expense Level**	$ 446,845	$ 487,644	$ 572,293		$ **502,261**	$ 553,519	$ **(51,258)**
	II. Per RUCO Surrebuttal							
7	Gallons	221,734	228,106	221,120	107,241	222,343	228,369	
8	Miles Driven	3,607,551	3,607,551	2,314,954	1,132,843	3,046,543	2,960,186	
9	Fuel Cost	$ 608,781	$ 664,365	$ 779,691	$ 243,414	$ 656,071	$ 753,931	
10	Cost per Gallon	$ 2.75	$ 2.91	$ 3.53	$ 2.27	$ 2.95	$ 3.30	
11	Percentage Allocated to O&M	73.4%	73.4%	73.4%	73.4%	73.4%	73.4%	
12	**Expense Level**	$ 446,845	$ 487,644	$ 572,293	$ 178,666	$ 481,556	$ 553,519	$ (71,963)
13	**Difference**					$ (20,705)		$ (20,705)

Notes and Source
Per UNSG: Response to RUCO 10.1 - Income - Fleet Fuel Expense (Excel file)
Line 4: Per UNSG workpaper provided in resposne to RUCO 10.1; difference between this and results of Line 3 / Line 1 attributable to UNSG showing a simple average, rather than a weighted average
Line 10: Line 9 / Line 7
Col.D: UNSG response to RUCO 11-36 - see summary at page 2 of this Schedule
Col.E: Sum of Columns A-D / 3.5 years

7/27/2009 12:21 PM

UNS GAS, INC.
CALENDAR YEAR 2006
RUCO 1.94 DATA - CORRECTED

Docket No. G-04204A-08-0571
Attachment RCS-7
Schedule C-8 Revised
Page 2 of 3

Fleet Fuel Expense by Month, January 2006 through June 2009

Included in "RUCO 10.1 - Income - Fleet Fuel Expense.xls" as backup for Dukes rebuttal testimony

Month	Amount	$/Gal	Gallons	Miles
Jan-06	$52,838.48	$2.51	21,019	
Feb-06	$42,722.90	$2.51	17,029	
Mar-06	$49,847.40	$2.59	19,210	
Apr-06	$54,739.50	$2.94	18,609	
May-06	$61,607.25	$3.13	19,672	
Jun-06	$57,594.59	$3.02	19,066	
Jul-06	$58,480.84	$3.01	19,439	
Aug-06	$58,787.62	$2.98	19,698	
Sep-06	$52,430.22	$2.67	19,618	
Oct-06	$44,502.16	$2.46	18,113	
Nov-06	$42,569.04	$2.47	17,257	
Dec-06	$32,660.68	$2.51	13,004	
Totals	$608,780.68	$2.73	221,734	0

Supplemental Response to RUCO 1.94

The "Miles" column in the Excel file RUCO 1.94 2006 was left blank when submitted to RUCO, without explanation. The reason this column is blank is that in 2006 the UNS Gas vehicles had not been fully loaded into the Tucson Electric Power Fleet Management system. UNS Gas is unable to give an accurate mileage account for 2006. The miles traveled in 2007 should be close to what was traveled in 2006.

Month	Amount	$/Gal	Gallons	Miles
Jan-07	$47,254.96	$2.43	19,413	287,170
Feb-07	$43,322.76	$2.48	17,468	286,775
Mar-07	$56,357.48	$2.74	20,549	315,877
Apr-07	$55,147.78	$2.99	18,445	332,610
May-07	$60,392.52	$3.09	19,551	273,648
Jun-07	$58,311.73	$3.07	18,999	357,882
Jul-07	$62,799.71	$3.00	20,954	310,803
Aug-07	$58,317.27	$2.85	20,436	352,954
Sep-07	$52,494.63	$2.85	18,441	281,905
Oct-07	$58,071.08	$3.00	19,349	299,792
Nov-07	$58,494.37	$3.26	17,947	328,348
Dec-07	$53,400.33	$3.23	16,554	179,787
Totals	$664,364.62	$2.92	228,106	3,607,551
Jan-08	$74,435.43	$3.17	23,502	216,237
Feb-08	$62,546.23	$3.26	19,215	220,381
Mar-08	$67,434.32	$3.58	18,843	207,156
Apr-08	$73,497.80	$3.73	19,685	178,971
May-08	$79,282.01	$4.05	19,568	200,136
Jun-08	$66,565.85	$4.35	15,302	183,716
Jul-08	$83,015.15	$4.32	19,234	171,416
Aug-08	$73,090.59	$3.97	18,392	210,901
Sep-08	$70,153.68	$3.78	18,552	166,329
Oct-08	$61,567.95	$3.24	18,993	217,413
Nov-08	$39,643.15	$2.50	15,859	147,355
Dec-08	$28,458.38	$2.04	13,975	194,943
Totals	$779,690.54	$3.50	221,120	2,314,954
Jan-09	$43,261.78	$2.12	20,439	191,693
Feb-09	$36,315.38	$2.20	16,500	163,407
Mar-09	$37,587.88	$2.12	17,693	204,036
Apr-09	$41,342.35	$2.32	17,794	190,434
May-09	$42,135.68	$2.28	18,506	182,493
Jun-09	$42,770.81	$2.62	16,309	200,780
Totals	$243,413.88	$2.28	107,241	1,132,843

Source: UNSG Response to RUCO 11-36

UNS GAS, INC.
FLEET FUEL EXPENSE
Updated Adjustment
Allocation to FERC Expense Accounts

Docket No. G-04204A-08-0571
Attachment RCS-7
Schedule C-8 Revised
Page 3 of 3

Line No.	FERC Account	Percent		Allocation UNSG Reb. Adjustment		Allocation RUCO Surreb. Adjustment		Difference
		(A)		(B)		(C)		(D)
1	0807	0.08%	$	(41)	$	(58)	$	(17)
2	0856	0.15%	$	(75)	$	(105)	$	(30)
3	0870	3.28%	$	(1,682)	$	(2,362)	$	(680)
4	0874	15.18%	$	(7,779)	$	(10,922)	$	(3,142)
5	0875	2.14%	$	(1,098)	$	(1,542)	$	(444)
6	0876	1.97%	$	(1,012)	$	(1,421)	$	(409)
7	0877	0.31%	$	(160)	$	(224)	$	(64)
8	0878	14.28%	$	(7,321)	$	(10,278)	$	(2,957)
9	0879	5.55%	$	(2,844)	$	(3,993)	$	(1,149)
10	0880	7.11%	$	(3,646)	$	(5,118)	$	(1,473)
11	0885	2.69%	$	(1,377)	$	(1,934)	$	(556)
12	0887	5.83%	$	(2,989)	$	(4,196)	$	(1,207)
13	0889	0.17%	$	(85)	$	(119)	$	(34)
14	0891	0.03%	$	(15)	$	(21)	$	(6)
15	0892	4.77%	$	(2,443)	$	(3,430)	$	(987)
16	0893	1.51%	$	(773)	$	(1,085)	$	(312)
17	0894	0.09%	$	(48)	$	(67)	$	(19)
18	0901	0.55%	$	(283)	$	(397)	$	(114)
19	0902	8.97%	$	(4,598)	$	(6,455)	$	(1,857)
20	0903	11.20%	$	(5,740)	$	(8,058)	$	(2,318)
21	0905	0.03%	$	(13)	$	(19)	$	(5)
22	0908	1.01%	$	(520)	$	(729)	$	(210)
23	0921	-0.28%	$	146	$	205	$	59
24	0921	13.20%	$	(6,767)	$	(9,500)	$	(2,733)
25	0930	0.01%	$	(3)	$	(4)	$	(1)
26	0932	0.19%	$	(96)	$	(134)	$	(39)
27	Totals	100.00%	$	(51,260)	$	(71,965)	$	(20,705)
28	**Total Adjustment from page 1**		**$**	**(51,258)**	**$**	**(71,963)**	$	**(20,705)**

Notes and Source
Per UNSG: Response to RUCO 10.1 - Income - Fleet Fuel Expense (Excel file)
Line 27: difference between amount on line 21 and amount from page 1 due to rounding

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Postage Expense Adjustment
Test Yeat Ended June 30, 2008

Docket No. G-04204A-08-0571
Attachment RCS-7
Schedule C-13 (new)
Page 1 of 1

Line No.	Description		Amount	Reference
1	Number of Customer Bills - Unadjusted		1,739,076	Co. Schedule H-2
2	Increase in Postage Rates '09		$0.02	
3	09 increase in postage rates/Unadjusted customers	$	34,782	Line 1 * Line 2
4	UNSG Customer Annualization			UNSG Schedule H2 P1
5	RUCO Customer Annualization Postage	$	-	Line 4 * .44
6	Postage Expense Adjustment - Increase Expense	$	34,782	Line 3 + Line 5
7	Less: UNSG Postage Expense Adjustment As Filed (Bates Nos. UNSG0571/02494 & UNSG0571/02555 - 02562)		$12,750	Misc Expenses Pro Forma
8	Incremental RUCO Postage Expense Adjustment	$	22,031	Line 6 - Line 7

Notes and Source

UNSG's response to RUCO 11-46

Line 4: RUCO recommends rejection of UNSG's proposed Customer Annualization, which would decrease test year revenue.

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Attachment RCS-8
Copies of Non-Confidential UNS Gas' Responses to Data Requests and Workpapers Referenced in the Surrebuttal Testimony and Schedules of Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
RUCO-10.1	Mr. Dukes' Rebuttal supporting workpaper for UNSG's proposed revised payment lag for Purchased Gas Expense	No	1	2
RUCO-11-6	No analysis of impact of participation in previous El Paso rate case at FERC	No	1	3
RUCO-11-8	Affiliate TEP became a customer of El Paso after last EPNG rate case at FERC	No	1	4
RUCO-11-9	No analysis of impact of participation in previous Transwestern Pipeline rate case at FERC	No	1	5
RUCO-11-10	Allocation of FERC proceeding costs among UNSE's affiliates	No	1	6
RUCO-11-12	UNSG intervention in FERC proceedings; no analysis of impact of participation	No	4	7 - 10
RUCO-11-13	UNSG's calculation of $9 million and $5.4 million amounts on page 2 of Hutchens' rebuttal testimony	No	2	11 - 12
RUCO-11-18	UNSG cost savings not reflected in the test year	No	1	13
RUCO-11-19	Annual cost reduction from having Walmart accept customer payments	No	1	14
RUCO-11-21	Accrued liability for vacation related to ADIT debit-balance items	No	1	15
RUCO-11-24	ADIT treatment for rate base	No	1	16
RUCO-11-25	ADIT treatment for rate base	No	1	17
RUCO-11-26	Lead lag treatment for accrued vacations and accrued pension liability	No	1	18
RUCO-11-27	Cash working capital: Purchased gas payment lag (without voluminous attachments)	No	4	19 - 22
RUCO-11-28	Post test year plant admissions	No	2	23 - 24
RUCO-11-30	UNSG reviewed CWIP for post test year plant	No	1	25
RUCO-11-32	Customer Advances admissions	No	2	26 - 27
RUCO-11-36	Fleet Fuel Expense (without voluminous attachments)	No	4	28 - 31
RUCO-11-38	Assumption detail for Grant rebuttal testimony 2009-2011 forecasts: not appropriate for ratemaking	No	10	32 - 41
RUCO-11-40	Projected 2010 Payroll Expense adjustment	No	3	42 - 44
RUCO-11-46	Postage expense	No	8	45 - 52
	Total Pages Including this Page		52	

UNS Gas
Purchased Gas Lag
Test Year Ending June 30, 2008

Service Month	Service Period Begin	Service Period End	Amount Paid	Payment Date	Lag Days (a)	Dollar Days
BP Energy Company						
July -	7/1/2007	7/31/2007	2,892,390	8/20/2007	35.00	101,233,667
August -	8/1/2007	8/31/2007	2,811,862	9/20/2007	35.00	98,415,166
September -	9/1/2007	9/30/2007	2,693,603	10/22/2007	36.50	98,316,498
October -	10/1/2007	10/31/2007	5,507,132	11/20/2007	35.00	192,749,607
November -	11/1/2007	11/30/2007	7,297,535	12/20/2007	34.50	251,764,943
December -	12/1/2007	12/31/2007	16,000,000	1/7/2008	22.00	352,000,000
December -	1/1/2008	1/15/2008	10,000,000	1/22/2008	14.00	140,000,000
January -	1/16/2008	1/31/2008	9,000,000	2/5/2008	12.50	112,500,000
January -	2/1/2008	2/15/2008	9,000,000	2/20/2008	12.00	108,000,000
February -	2/16/2008	2/29/2008	9,373,701	3/19/2008	25.50	239,029,379
March -	3/1/2008	3/31/2008	12,389,177	4/22/2008	37.00	458,399,562
April -	4/1/2008	4/30/2008	7,801,472	5/22/2008	36.50	284,753,743
May -	5/1/2008	5/31/2008	7,264,481	6/20/2008	35.00	254,256,849
June -	6/1/2008	6/30/2008	7,826,991	7/21/2008	35.50	277,858,167
			109,858,344			2,969,277,581
El Paso Natural Gas Co						
July -	7/1/2007	7/31/2007	379,421	8/24/2007	39.00	14,797,438
August -	8/1/2007	8/31/2007	377,627	9/25/2007	40.00	15,105,098
September -	9/1/2007	9/30/2007	388,581	10/25/2007	39.50	15,348,942
October -	10/1/2007	10/31/2007	438,071	11/25/2007	40.00	17,522,849
November -	11/1/2007	11/30/2007	976,464	12/21/2007	35.50	34,664,462
December -	12/1/2007	12/31/2007	1,273,618	1/25/2008	40.00	50,944,716
January -	1/1/2008	1/31/2008	1,267,429	2/25/2008	40.00	50,697,160
February -	2/1/2008	2/28/2008	1,239,857	3/24/2008	39.50	48,974,366
March -	3/1/2008	3/31/2008	1,190,404	4/22/2008	37.00	44,044,947
April -	4/1/2008	4/30/2008	568,207	5/27/2008	41.50	23,580,588
May -	5/1/2008	5/31/2008	338,302	6/23/2008	38.00	12,855,459
June -	6/1/2008	6/30/2008	352,906	7/25/2008	39.50	13,939,806
			8,790,888			342,475,831
Transwestern Pipeline Co						
July -	7/1/2007	7/31/2007	104,768	8/13/2007	28.00	2,933,518
August -	8/1/2007	8/31/2007	104,727	9/14/2007	29.00	3,037,089
September -	9/1/2007	9/30/2007	101,557	10/12/2007	26.50	2,691,256
October -	10/1/2007	10/31/2007	260,164	11/9/2007	24.00	6,243,936
November -	11/1/2007	11/30/2007	252,179	12/13/2007	27.50	6,934,912
December -	12/1/2007	12/31/2007	263,779	1/14/2008	29.00	7,649,581
January -	1/1/2008	1/31/2008	264,531	2/11/2008	26.00	6,877,800
February -	2/1/2008	2/28/2008	246,162	3/13/2008	28.50	7,015,611
March -	3/1/2008	3/31/2008	302,830	4/11/2008	26.00	7,873,585
April -	4/1/2008	4/30/2008	331,575	5/12/2008	26.50	8,786,729
May -	5/1/2008	5/31/2008	241,646	6/12/2008	27.00	6,524,454
June -	6/1/2008	6/30/2008	182,318	7/11/2008	25.50	4,649,105
			2,656,236			71,217,578
			121,305,468			3,382,970,990
Average Lag Days				27.89		

(a) Measured from midpoint of service month to payment date.

Current Payments made to BP Energy after TY Ending June 30, 2009

Service Period Begin	Service Period End	Amount Paid	Payment Date	Lag Days (a)	Dollar Days
7/1/2008	7/31/2008	4,755,012	8/20/2008	35.00	166,425,403
8/1/2008	8/31/2008	3,813,688	9/22/2008	37.00	141,106,473
9/1/2008	9/30/2008	1,169,749	10/15/2008	29.50	34,507,591
10/1/2008	10/31/2008	1,589,392	11/25/2008	40.00	63,575,692
11/1/2008	11/15/2008	2,932,485	11/25/2008	17.00	49,852,248
11/16/2008	11/30/2008	4,333,170	12/8/2008	15.00	64,997,546
12/1/2008	12/15/2008	3,717,098	12/22/2008	14.00	52,039,373
12/16/2008	12/31/2008	7,194,073	1/8/2009	15.50	111,508,127
12/16/2008	12/31/2008	956,319	1/20/2009	27.50	26,298,784
1/1/2009	1/15/2009	3,760,981	1/22/2009	14.00	52,653,733
1/16/2009	1/31/2009	6,411,461	2/6/2009	13.50	86,554,721
2/1/2009	2/15/2009	3,422,333	2/20/2009	12.00	41,067,995
2/16/2009	2/28/2009	4,187,566	3/6/2009	12.00	50,250,797
3/1/2009	3/15/2009	3,261,816	3/20/2009	12.00	39,141,796
3/16/2009	3/31/2009	3,548,797	4/9/2009	16.50	58,555,151
4/1/2009	4/15/2009	1,609,806	4/24/2009	16.00	25,756,903
4/16/2009	4/30/2009	1,481,302	5/8/2009	15.00	22,219,537
5/1/2009	5/15/2009	747,245	5/26/2009	18.00	13,450,402
5/16/2009	5/31/2009	791,607	6/10/2009	17.50	13,853,120
		59,683,901			1,113,815,392
			18.66		

Payment Lag Adjustment - For Rebuttal

Service Period Begin	Service Period End	Amount Paid	Payment Date	Lag Days (a)	Dollar Days
BP Energy Company					
12/1/2008	12/15/2008	3,717,098	12/22/2008	14.00	52,039,373
12/16/2008	12/31/2008	7,194,073	1/8/2009	15.50	111,508,127
12/16/2008	12/31/2008	956,319	1/20/2009	27.50	26,298,784
1/1/2009	1/15/2009	3,760,981	1/22/2009	14.00	52,653,733
1/16/2009	1/31/2009	6,411,461	2/6/2009	13.50	86,554,721
2/1/2009	2/15/2009	3,422,333	2/20/2009	12.00	41,067,995
2/16/2009	2/28/2009	4,187,566	3/6/2009	12.00	50,250,797
3/1/2009	3/15/2009	3,261,816	3/20/2009	12.00	39,141,796
3/16/2009	3/31/2009	3,548,797	4/9/2009	16.50	58,555,151
4/1/2009	4/15/2009	1,609,806	4/24/2009	16.00	25,756,903
4/16/2009	4/30/2009	1,481,302	5/8/2009	15.00	22,219,537
5/1/2009	5/15/2009	747,245	5/26/2009	18.00	13,450,402
5/16/2009	5/31/2009	791,607	6/10/2009	17.50	13,853,120
		41,090,405			593,350,439
			14.44		
El Paso Natural Gas Co					
		8,790,888			342,475,831
Transwestern Pipeline Co					
		2,656,236			71,217,578
		52,537,528			1,007,043,848
			19.17		

**UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009**

RUCO 11.6 Does UNSG have any analyses of the impact of its participation in the last EPNG rate case at FERC? If not, explain fully why not. If so, please identify, explain and provide a copy of all such analyses.

RESPONSE: UNS Gas does not have any analysis on the impact of its participation in the last EPNG rate case at FERC. It is impossible to determine the impact of one individual company's participation in a case whether it is litigated or settled, since there are many factors at issue and many other parties involved that may affect the case. There is no objective measure to determine the impact of any one party.

RESPONDENT: Theresa Mead

WITNESS: David Hutchens

**UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009**

RUCO 11.8 Did the last EPNG rate case at FERC have any impact on UNSG's affiliate, Tucson Electric Power? If not, explain fully why not. If so, please identify, quantify and explain the potential impact.

a. Show the total amount of cost from participating in that FERC case by component.
b. Show in detail how thc cost of participating in that FERC case was apportioned among each of the affiliates.

RESPONSE: In its last rate case, FERC Docket No. 95-363, EPNG filed its Settlement Proposal on December 6, 2007. FERC issued its order accepting the Settlement Proposal on August 31, 2007. TEP did not become a customer of EPNG until April 2007; therefore, TEP did not participate in the rate case.

a. Not applicable.

b. Not applicable.

RESPONDENT: Theresa Mead

WITNESS: David Hutchens

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RUCO 11.9 Does UNSG have any analyses of the impact of its participation in the last Transwestern Pipeline rate case at FERC? If not, explain fully why not. If so, please identify, explain and provide a copy of all such analyses.

RESPONSE: UNS Gas does not have any analysis on the impact of its participation in the last Transwestern Pipeline rate case at FERC. It is impossible to determine the impact of one individual company's participation in a case, whether it is litigated or settled, since there are many factors at issue and many other parties involved that may affect the case. There is no objective measure to determine the impact of any one party.

RESPONDENT: Theresa Mead

WITNESS: David Hutchens

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RUCO 11.10 How does UNSG coordinate the cost of participating in FERC proceedings with its affiliates, including but not limited to TEP, UNS Electric, and others? Explain fully.

RESPONSE: In matters where UNS Gas and other affiliates intervene, expenses would be allocated equally.

RESPONDENT: Theresa Mead

WITNESS: David Hutchens

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RUCO 11.12

Refer to Mr. Dukes' rebuttal testimony at pages 27-28. Please provide the following information for each year, 2004-2008 and for year-to-date 2009:

a. Identify each FERC case in which UNSG has participated.
b. Identify the cost of UNSG's participation in each such FERC case, by amount and by account.
c. Identify the outside legal cost of UNSG's participation in each such FERC case, by amount and by account.
d. Identify and explain the issues that concerned UNSG in each such FERC case.
e. Identify, quantify and explain the impact that UNSG's participation had on the results of each such FERC case.
f. Provide all analyses and cost-benefit evaluations that UNSG has documenting the impact of UNSG's participation and litigation in each such FERC case.
g. Provide all documentation used by UNSG in its evaluation of how much legal expense to incur on each such FERC case.

RESPONSE:

a. UNS Gas objects to providing information for years 2004 – 2005 as that information does not have any relevance to the current UNS Gas rate case. Refer to the response to RUCO 11.11.a. for FERC proceedings UNS Gas has intervened in from the start of the test year to present. FERC proceedings UNS Gas intervened in from January 2006 – June 2007 include:

El Paso Natural Gas Co.

- RP04-19 - Filing of revised tariff sheets to FERC Gas Tariff for additional scheduling flexibility for EPNG shippers and proposing 5-tier scheduling mechanism
- RP04-110 - Revised tariff sheets to FERC Gas Tariff to establish procedures for re-designating primary rights under transportation service agreement; FERC Order issued 02/05/04 accepting procedures, subject to condition
- RP04-248 & RP04-251 - Revised tariff sheets to FERC Gas Tariff to implement new portfolio of Imbalance Management Services for shippers on its pipeline system in Docket RP04-248; filing of Proforma tariff sheets under FERC Gas Tariff in compliance with FERC Order Nos. 637, 637-A and 637-B in Docket RP04-251 with request that matter be consolidated with Docket RP04-248; offer of settlement filed with FERC 09/13/04
- CP04-368 - Application for authorization to abandon, by removal, its 7.1 miles 10¾-inch diameter Nevada Loop Line No. 2112 and replace segments of its 16-inch diameter Nevada Loop Line No. 2121, totaling 17.2 miles, located in Mohave County, AZ

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- RP05-422 - General rate case under Section 4 of the FERC Rules and Regulations; 07/12/05 UNS Gas filed Protest, Request for Maximum Suspension, Request for Summary Rejections of Primary and First Alternative Cases, Request for Evidentiary Hearing and Motion to Intervene
- RP-06-102 - Revised tariff sheets to FERC Gas Tariff to revise certain bid evaluation options available for capacity release transactions to provide for multi-month releases with varying monthly contract quantities
- RP06-162 - Non-conforming Critical Meter Limit Agreement
- CP06-57 - Application for certificate of public convenience and necessity authorizing EPNG to acquire, own and operate 24" O.D. lateral pipeline facilities, with appurtenances, located in Pinal and Maricopa Counties, AZ from SRP
- CP06-69 - Petition for Exemption of Temporary Acts and Operations from Certificate Requirements seeking approval of exemption from certificate requires to perform temporary activities related to drilling test well and performing other activities to assess feasibility of developing underground natural gas storage facility in Pinal County, AZ
- RP06-310 - Tariff sheets to FERC Gas Tariff to add rates for service to Blythe, CA
- RP06-354 – East Valley Lateral Compliance Tariff Sheets
- RP06-369 - Revised tariff sheet to FERC Gas Tariff and Rate Schedule OPAS agreement with SRP
- RP06-372 - Revised tariff sheets to FERC Gas Tariff and 4 firm TSAs with APS and UNS Gas
- RP06-374 - Revised tariff sheet to FERC Gas Tariff and 7 firm TSAs with SRP
- RP06-418 - Revised tariff sheets to FERC Gas Tariff and 5 firm TSAs with AEPCO, UNS Gas and Aera Energy
- RP-06-600 - Revised tariff sheet to FERC Gas Tariff and 4 firm TSAs with Texas Gas Service Co.
- RP06-609 - Revised tariff sheets to FERC Gas Tariff to update discount provisions to incorporate most up-to-date list of permissible generic discounts
- RP06-615 - Revised tariff sheets to FERC Gas Tariff and 3 firm TSAs with PNM
- CP07-9 - Application for permission and approval to abandon, by sale to Transwestern, an undivided ownership interest in East Valley Lateral pipeline facilities located in Pinal and Maricopa Counties, AZ

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- RP07-108 - Request to waive and/or reduce certain penalties and charges under FERC Gas Tariff for time period of 11/30/30-12/3/06
- RP07-144 - 9 Rate Schedule FT-1 TSAs containing revised exhibits with UNS Gas, APS and PNM
- RP07-152 - Revised tariff sheet to FERC Gas Tariff, Rate Schedule FT-1 TSA, 2 Rate Schedule FT-H TSAs and 1 Rate Schedule OPAS agreement all with SRP
- RP07-354 - Revised tariff sheets to FERC Gas Tariff to update exhibits to Form of Service Agreements applicable to service under EPNG's firm and operator rate schedules to match its current contracting practices
- RP07-390 - Revised tariff sheets to FERC Gas Tariff re TSAs

<u>Transwestern Pipeline</u>

- RP05-689 - Operating Balance Agreement (OBA) that contains a provision that is supplemental to the form of OBA set forth in and in accordance with FERC Gas Tariff
- RP05-695 - Revised tariff sheet to FERC Gas Tariff to set forth the factors and calculations used in determining the adjustments to and to revise settlement base rates to be effective 11/01/05
- RP05-696 - Revised tariff sheet to FERC Gas Tariff to set forth the new TCR II reservation surcharges to be effective 11/01/05
- RP06-604 - Revised tariff sheets to FERC Gas Tariff to remove outdated tariff provisions, update tariff information and terminology, clarify certain tariff provisions and conform to FERC policy, reorganize rate sheets, Rate Schedules and capacity release provisions and make minor clarifications and corrections to Tariff
- RP06-611 - Revised tariff sheets to FERC Gas Tariff to remove the TCR II Surcharge
- RP06-612 - Revised tariff sheet to FERC Gas Tariff to revise Settlement Base Rates in accordance with Transwestern's Stipulation and Agreement filed on 05/02/95 in Dkt. RP95-271, as amended
- RP06-614 – Rate increase application
- CP06-459 - Application seeking authority to construct and operate (i) appx. 25 miles of 36" diameter pipeline loop in 2 segments on existing San Juan Lateral in San Juan and McKinley Counties, NM, (ii) new 259-mile pipeline consisting of 36" and 42" diameter pipe extending southward from existing mainline near Ash Fork in Yavapai County, AZ through Coconino and Maricopa Counties, AZ and terminating at beginning of EPNG East Valley Lateral near City of Coolidge, AZ and (iii) customer laterals, meter stations and ancillary facilities ("Phoenix Pipeline Project")

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b. The cost of UNS Gas' participation in each individual FERC case is not tracked on an individual case basis.

c. The outside legal cost of UNS Gas' participation in each individual FERC case is not tracked on an individual case basis.

d. All comments, testimony, etc. filed by UNS Gas in any of the FERC dockets in response to RUCO 11.11.a. or RUCO 11.12.a. above are publicly available data and can be viewed on the FERC website under Docket No. RP08-426. The link to the FERC website is: http://www.ferc.gov/. All non-public material is subject to attorney-client privilege. UNS Gas objects to disclosing any analysis or documents in closed or current FERC proceedings as doing so could disadvantage the Company in its litigation and/or settlement of open proceedings or future proceedings.

e. UNS Gas does not have any analysis on the impact of its participation in any of the FERC proceedings referenced in RUCO 11.11.a. nor in the FERC proceedings referenced in response to RUCO 11.12.a. above. It is impossible to determine the impact of one individual company's participation in a case whether it is litigated or settled, since there are many factors at issue and many other parties involved that may affect the case. There is no objective measure to determine the impact of any one party.

f. UNS Gas objects to disclosing any analysis or documents in closed or current FERC proceedings as doing so could disadvantage the company in its litigation and/or settlement of open proceedings or future proceedings. Additionally, all non-public material is subject to attorney client-privilege.

g. UNS Gas does not do an evaluation in advance of how much legal expense it should incur on each FERC proceeding in which it participates as it is impossible to know whether proceedings will be settled or fully litigated, and how long or complex these proceedings will be.

RESPONDENT: Theresa Mead

WITNESS: David Hutchens

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RUCO 11.13 Refer to Mr. Hutchens' rebuttal testimony at page 2. Provide complete supporting calculations, work papers and Excel files for the $9 million and $5.4 million amounts mentioned on page 2, line 16.

RESPONSE: Please see workpapers provided in response to RUCO 10.1.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes, Dave Hutchens

UNS GAS, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2008

	UNSG As Filed 11/7/08	ACC As Filed 6/8/09	ACC Difference	RUCO As Filed 6/8/09	RUCO Difference	UNSG Revised 7/8/09
Rate Case Revenue Annualization	1,448,476	1,797,514	349,038	1,448,476		1,448,476
Customer Annualization	(516,003)	655,768	1,171,771	-	516,003	(516,003)
Weather Normalization	(882,453)	(903,889)	(21,436)	(882,453)	-	(882,453)
Normalize Outside Legal Expense	305,984	-	305,984	88,310	217,674	305,984
Bad Debt Expense	63,211	(123,416)	186,627	63,211		63,211
Adjusted Operating Income	$11,600,004	$13,544,256		$13,090,781		$11,693,460
Operating Income Deficiency	$4,350,643	$1,164,915		$490,494		$4,439,710
Fair Value Addition (Pre-Tax)	$1,442,389	$912,685		$23,382		$1,353,322
Fair Value Operating Income Deficiency	$5,793,032	$2,077,600		$513,876		$5,793,032
Gross Revenue Conversion Factor	1.6366	1.6343		1.6366		1.6366
Increase in Gross Revenue Requirement	$9,480,876	$3,395,423		$841,000		$9,480,876

	ACC		RUCO	
Additional Exp And Rev if changed to Commission Precedent $ for $ changes	1,991,984		733,677	
Fair Value Difference	3,620,000	a	3,808,000	b
Additional Revenue to be added to their filing if they followed precedent	5,611,984		4,541,677	
What their increases would have been had they followed precedent on the above items	$ 9,007,407		$ 5,382,677	

Note a: From Kent Grant's testimony

Note b: $4.7M (Smith's testimony) less $841K

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RUCO 11.18 Refer to Mr. Hutchens' rebuttal testimony at page 7, concerning the overall slumping economy.

a. Identify, quantify and explain all steps taken by UNSG in 2008 and 2009 to reduce costs.

b. For each cost reduction effort undertaken by UNSG identified in response to part a, please identify exactly where, and in what amount, each such cost reduction effort has been reflected in UNSG's determination of the Company's requested revenue increase.

RESPONSE: a. See summary of savings realized below:

UNG UNS Gas, Inc

	Jul 07 thru Jun 08	Jul 08 thru Jun 09	Associated reduction:	
A10 Labor Costs	10,929,439	10,889,945	(39,494)	Reduced Overtime, reduced FTEs
158 Supplemental Service	155,874	28,208	(127,665)	Meter reading brought in-house
162 Repairs & Maintenance	263,896	249,701	(14,196)	Reduced vehicle maintenance
A59 Training & Travel	283,462	263,265	(20,197)	Company reduction focus
406 Communications	758,366	535,060	(223,305)	Contract re-negotiation
B64 Transportation	652,670	454,440	(198,230)	Vehicle depreciation reduction

b. These savings are not reflected in the test year. Other increases as reflected within the overall operating cost are still higher than test year and will be in 2009 and 2010. The Company's cost savings efforts have only resulted in mitigating the increases and the effect of regulatory lag.

RESPONDENT: Paul Coleman

WITNESS: David Hutchens

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RUCO 11.19 Refer to Mr. Hutchens' rebuttal testimony at pages 12- 13, lines 1-3.

a. Referring to page 13, lines 1-3, please identify all expenses, by account, in the test year for payment of fees by UNSG for payments made at check cashing centers and/or other outside payment locations.
   i. Identify, quantify and explain fully how the discontinuance of the payment of such fees would impact expense on a going-forward basis.

b. Refer to page 12, please identify the test year expense for payments and/or fees paid to Circle K for Circle K's acceptance of customer utility bill payments.
   i. Identify, quantify and explain fully how the discontinuance of the payment of such fees would impact expense on a going-forward basis.

c. Referring to page 12, identify, quantify and explain the anticipated annual cost reductions to UNSG from having Walmart accept customer payments.

RESPONSE:

a. ACE America's Cash Express - $25,002.08
   Other Outside Payment Locations* - $18,770.92

   i. As of July 1, 2009, UNS Gas will no longer incur expenses for payments made at any ACE (America's Cash Express) locations.

   Effective October 9, 2009, UNS Gas will incur a cost of 1.5 cents per payment made at the Other Outside Payment Locations. The cost is charged by the processing company, FISERV, for electronic delivery of payments. Due to an anticipated decline in volume of payments taken by Other Outside Locations, annual expenses are projected at less than $300.

b. $0. The ability of Circle K to accept UNS Gas payments never materialized.

   i. Not applicable.

c. UNS Gas incurs a 1.5 cent cost per payment made at a Walmart location. The cost is charged by the processing company, FISERV, for electronic delivery of payments. The anticipated annual cost reduction using Walmart is approximately $42,000. All costs are based on assumptions. Actual costs will be dependent on customer behavior.

*OA Quick Cash (Flagstaff); Radio Shack (Show Low & Lakeside);IGA Food & Drug (Sedona)

RESPONDENT: Lindy Sheehey

WITNESS: David Hutchens

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RUCO 11.21 Refer to Ms. Kissinger's rebuttal testimony at pages 2-3. Identify the beginning and end-of-test year accrued liability amounts on UNSG's books for each of the following items:

a. Accrued vacation
b. Accrued pension liability
c. Accrued stock based compensation liability

RESPONSE: a.-c. Please see the table below.

	7/1/2007	6/30/2008
a. Accrued vacation	$389,233	$438,776
b. Accrued Pension	$2,625,165	$1,732,676
c. Accrued Stock Based Compensation Liability	$0	$0

RESPONDENT: Georgia Hale

WITNESS: Karen Kissinger

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RUCO 11.24 Refer to Ms. Kissinger's rebuttal testimony at page 3. Please admit that the "Commission approved method" of addressing the amount of ADIT balance to be included in rate base is to review all of the testimony and briefs filed in each utility case and to decide based on the facts and evidence in that case. If your response is anything other than an unqualified admission, explain fully and provide all support relied upon.

RESPONSE: The Commission's method in addressing the amount of ADIT balance to be included in rate base is to review all of the testimony and briefs filed in each utility case and to decide the case based on the facts and evidence in that case.

The Commission's method is to consider the facts and evidence in light of its past practices and treatment of specific items in other cases with the same facts and evidence. By so doing, the Commission provides consistency of treatment among the ratepayers of Arizona.

RESPONDENT: Gail Boswell

WITNESS: Karen G. Kissinger

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RUCO 11.25 Refer to Ms. Kissinger's rebuttal testimony at page 3. Please identify each and every Commission Decision and the specific language within each such decision which Ms. Kissinger believes provides a clear statement of the "accepted Commission approved methods" for evaluating a utility's ADIT balance for inclusion in, or exclusion from, rate base.

RESPONSE: In the cases referenced on page 3 of the Rebuttal Testimony, there were no challenges of the inclusion of these items in rate base. Therefore, there was no need for the Commission to explicitly discuss these items in its Decisions.

RESPONDENT: Gail Boswell

WITNESS: Karen G. Kissinger

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RUCO 11.26 Please provide all details of UNSG's lead-lag study in the current case which address how UNSG measured the cash payment lag associated with each of the following items:

a. Accrued vacation
b. Accrued pension liability
c. Accrued stock based compensation liability

RESPONSE:

a. UNS Gas did not make any specific adjustments in the lead-lag study for Accrued vacation.

b. UNS Gas Pension and Benefit payment lag reflects the payment lag for cash payments made to the pension funds trustees.

c. UNS Gas had no accrued stock based compensation liability.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

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RUCO 11.27 Refer to Mr. Dukes' rebuttal testimony at page 2.

a. Admit that UNSG provided no supporting calculations with its rebuttal testimony for its new over 2000% increase in its claim for cash working capital ($97,967 to $2,183,948). If your response is anything but an unqualified admission, explain fully.

b. Provide complete documentation including all Excel files and supporting calculations showing each payment relating to gas cost purchases from 1/1/2008 through the present.

c. Provide a copy of each gas purchase invoice from 1/1/2008 through the present.

d. Provide all payment documentation for each gas cost invoice from 1/1/2008 through the present.

e. Provide a copy of the current and prior gas purchase contracts and all amendments thereto affecting payment terms.

f. Identify the "primary purchased gas vendor" referred to on page 2, line 7.

g. When did the "primary purchased gas vendor" change its payment terms?

h. Provide all documents relating to the change in gas purchase payment terms including but not limited to all correspondence, letters, legal documents, tariff filings, invoices, emails.

i. Identify all credit limitations, referenced at page 2, line 10.

j. Provide all correspondence relating to all such credit limitations.

k. Explain in detail what UNSG could do to address each such "credit limitation"?

l. Identify, and provide a copy of, the specific provisions in the contract or agreement with the "primary purchased gas vendor" that allowed the vendor to change the payment terms.

m. Did UNSG contest or object to the change in payment terms? If not, explain fully why not. If so, provide all documents showing that UNSG objected to the change in payment terms.

n. Identify the payment terms that are related to each gas vendor that could provide gas supply to UNSG.

o. Identify all conditions that would allow UNSG to pay for purchased gas from the "primary purchased gas vendor" on a monthly basis.

RESPONSE:

a. UNS Gas provided supporting workpapers and calculations.

b. This information was provided with workpapers in UNS Gas' response to RUCO 10.1.

c. Please see RUCO 11.27(c & d), Bates Nos. UNSG(0571)09887 to UNSG(0571)10033, on the enclosed CD for the gas purchase invoices and payment documentation for the period 1/1/2008 through the present. This file contains gas purchase invoices for BP Energy, Transwestern Pipeline and EPNG. The file also includes a summary of each vendor's invoices (with payment detail). Mr. Dukes' Rebuttal Testimony included a revision of payment lag days for gas purchases. The revised payment lag days calculation included BP Energy invoices for 12/1/08 through 5/16/09 because the payment timing to this vendor **changed** from thirty (30) days to every two (2) weeks. The revised payment lag days calculation did not include additional invoices for Transwestern Pipeline or EPNG because the payment timing to those vendors did not change; however attached file includes invoices for Transwestern Pipeline and EPNG for your review, in addition to BP Energy invoices used in the payment lag days calculation revised for Mr. Dukes' rebuttal testimony. Invoices for the vendors included in the lead-lag study as originally filed are identified by Bates Nos. UNSG0571/01980 through UNSG0571/02063.

d. Please see UNS Gas' response to RUCO 11.27.c. above.

e. Current gas purchase contract: Base Contract for Sale and Purchase of Natural Gas between BP Energy Company and UNS Gas, Inc. dated September 1, 2008.

First Amendment to Base Contract for Sale and Purchase of Natural Gas between BP Energy Company and UNS Gas, Inc. dated November 18, 2008.

Prior gas purchase contract: Natural Gas Supply and Transmission Management Agreement by and between Citizens Communications Company, Arizona Gas Division and BP Energy Company, dated October 28, 2002, but effective as of October 1, 2002.

Pleas see RUCO 11.27(e), Bates Nos. UNSG(0571)10034 to UNSG(0571)10135, on the enclosed CD.

f. British Petrolium Energy Company.

g. January 2008 – March 2008, and November 2008 – May 2009.

h. Please see RUCO 11.27(h) (Confidential), Bates Nos. UNSG(0571)10138 to UNSG(0571)10144, on the enclosed CD.

For the winter season 2007/2008, see emails and the Standby Letter of Credit dated December 28, 2007.

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For the winter season 2008/2009, see emails, Amendment to Base Contract dated November 18, 2008, and the Standby Letter of Credit dated October 30, 2008.

i. UNS Gas' primary purchased gas vendor (BP Energy) provides UNS Gas with an unsecured credit limit based upon its assessment of UNS Gas' creditworthiness. If the vendor's total exposure to UNS Gas exceeds that credit limit, it may decline to enter into additional transactions with UNS Gas until the exposure is below the credit limit, or it may request some form of performance assurance to cover the amount of the credit exposure in excess of the credit limit or to cover proposed new business. Such performance assurance may be in the form of a prepayment, a standby letter of credit, a performance bond, or a guaranty by another party.

Because UNS Gas is a winter-peaking gas distribution company, its exposure to its primary gas supplier is highest during the winter months of November through April. In each of the last two years, UNS Gas' exposure to BP Energy exceeded its credit limit. Therefore, UNS Gas negotiated terms to provide credit support in the form of more frequent payments (twice monthly) and a standby letter of credit, so that UNS Gas could continue to enter into new transactions with BP Energy.

j. Please see UNS Gas' response to RUCO 11.27.h above.

k. UNS Gas could make more frequent payments of amounts owed for gas supplied, could provide a standby letter of credit from a financial institution, or could curtail doing new business with the supplier, or a combination of these actions. The decision to provide a letter of credit vs. make prepayments depends on several factors including available credit under its revolving credit facility to issue letters of credit, the cost of issuing letters of credit, the amount of available cash on hand, and the interest rate that could be earned on the investment of excess cash.

l. Please see RUCO 11.27(e), UNSG(0571)10034 to UNSG(0571)10135,on the enclosed CD, and refer to Article IV—Security, of the Natural Gas Supply and Transportation Management Agreement dated October 28, 2002, and to Section 10.1—Financial Responsibility of the Base Contract dated September 1, 2008.

m. No, UNS Gas did not object to the change in payment terms. The vendor's request was reasonable in view of the size of the credit exposure compared to the credit limit provided, and therefore UNS Gas was willing to negotiate terms with the supplier that were agreeable to both parties.

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n. Please see UNS Gas' response to Staff's first set of data requests, JMK 1-1, in which all lead-lag workpapers were provided.

o. As long as the vendor's total exposure to UNS Gas is within the credit limit established for UNS Gas, UNS Gas may pay for purchased gas on a monthly basis.

RESPONDENT: Barbara McCormick, Dallas Dukes, Janet Zaidenberg-Schrum (parts c and d)

WITNESS: Dallas Dukes, Kentton C. Grant

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RUCO 11.28 Refer to Mr. Dukes' rebuttal testimony at page 4-5.

a. Please admit that replacement of old mains and services could reduce maintenance costs. If your response is anything but an unqualified admission, explain fully.

b. Please admit that additional transportation equipment could serve customer growth. If your response is anything but an unqualified admission, explain fully.

c. Please admit that replacing old transportation equipment with new equipment could reduce maintenance costs. If your response is anything but an unqualified admission, explain fully.

d. Please admit that all "post test year plant" that UNSG is requesting in rate base was in CWIP as of the end of the test year. If your response is anything but an unqualified admission, explain fully.

e. Please admit that all of the decisions cited on page 4, line 18, pertain to water utilities. If your response is anything but an unqualified admission, explain fully.

f. Please admit that UNSG is not a water utility. If your response is anything but an unqualified admission, explain fully.

g. Please admit that UNSG has not cited in its rebuttal testimony any decisions allowing post test year plant for energy utilities. If your response is anything but an unqualified admission, explain fully.

h. Please admit that other Commission decisions that were <u>not</u> cited in UNSG's rebuttal testimony have denied rate base inclusion of post test year plant. . If your response is anything but an unqualified admission, explain fully.

i. Please identify each Commission decision from 2004 through the present that addressed whether post test year plant should be included in rate base of which UNSG and its witnesses and counsel are aware.

RESPONSE:

a. Yes it could.

b. All transportation equipment is purchased to be used in providing natural gas service to existing customers and any new customers.

c. Yes it could.

d. Yes it was.

e. Yes they do.

f. UNS Gas is not a water company.

g. UNS Gas has not.

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h. The Commission has denied the inclusion of post test year plant in rate base in other decisions.

i. UNS Gas has not conducted an exhaustive survey of all Commission rate case decisions since 2004. However, several decisions have allowed post-test year plant in rate base, including:

- Rio Rico Utilities, Inc, Decision No. 67279 (October 5, 2004);
- Arizona Water Company, Decision No. 66849 (March 19, 2004);
- Bella Vista Water Company, Inc., Decision No. 65350 (November 1, 2002);
- Arizona-American Water Company, Decision No. 68864 (July 28, 2006); and
- Chaparral City Water Company, Decision No. 68176 (Sept. 30, 2005).

Moreover, in the prior UNS Gas rate case, the Commission noted in Decision No. 70011, page 8, that the Commission has allowed post-test year plant in rate base where there was an assurance that a mismatch of revenues did not occur, such as when the plant is revenue-neutral-- which is the case here.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

**UNS GAS, INC.'S RESPONSE TO
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RUCO 11.30 Refer to Mr. Dukes' rebuttal testimony at page 5, lines 5-7.

a. Identify the name and job title of each person who reviewed the CWIP projects and indicate whether they are a witness for UNSG gas in the current rate case.

b. Provide all written criteria that were considered by the people identified in response to part a, to evaluate whether an item of end of test year CWIP would produce additional revenue or not.

c. How did the Company determine that none of the service and main replacements would serve any new customers? Explain fully and provide all supporting analysis.

d. Does UNSG have any analysis to support its claim for post test year plant other than what was provided in UNSG workpapers UNSG 0571 / 03012 through 03015? If not, explain fully why not. If so, please identify and provide all additional support that UNSG has.

RESPONSE:

a. Carl Dabelstein, Manager of Plant Accounting TEP – not a witness

Diane Grant, Lead Plant Accountant TEP – not a witness

Paul Coleman, Director of Business Services UES – not a witness

Paula Smith, Operations Support Analyst UNS Gas – not a witness

Gary Smith, General Manager UNS Gas – retired employee/prior witness

Dallas J. Dukes, Manager Pricing and Economic Forecasting TEP – witness

b. Instructions were given verbally to identify "non-additional" revenue producing plant that had been invested in prior to the end of the test year that was not being installed for the purpose of meeting customer growth, was not being installed to serve new customers and investments that would have been made whether we added additional customers or not.

c. Replacements were identified whose primary purposes were to serve existing customers and would have been replaced regardless of potential customer additions.

d. Please see UNS Gas' response to RUCO 1.88.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

**UNS GAS, INC.'S RESPONSE TO
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RUCO 11.32 Refer to Mr. Dukes' rebuttal testimony at page 5.

a. Admit that UNSG's proposal to fail to offset rate base by the full amount of Customer Advances is simply inconsistent with prior Commission decisions, including, but not limited to, Decision No. 70011 in UNSG's last rate case. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

b. Admit that when UNSG receives a Customer Advance in the form of money, it has the use of that non-investor supplied money. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

c. Admit that Customer Advances are a non-investor supplied source of cost-free capital to the Company. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

d. Admit that UNSG does not reduce the CWIP base to which it applies an AFUDC rate by the amount of Customer Advances related to CWIP. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

e. Admit that Commission Rule A.A.C R 14-2-103, Schedule B-1 requires Customer Advances to be subtracted from rate base. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

f. Admit that Commission Rule A.A.C R 14-2-103, Schedule B-1 requires Customer Advances to be subtracted from rate base, without any exception for Customer Advances related to CWIP. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

g. Admit that Customer Advances are non-investor supplied capital when they are received by the utility. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

h. Admit that UNSG does not hold Customer Advances in an escrow account. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

i. Admit that it would be inappropriate for a utility to earn a return on non-investor supplied capital. If your response is anything but an unqualified admission, explain fully and provide supporting documentation.

RESPONSE: a. UNS Gas does not believe that it is inconsistent, as UNS Gas is requesting only the exclusion of the portion of advances already spent as of the end of the test year on plant not included in rate base. The Company is arguing that the portion already spent is not available as zero cost capital as of the end of the test year, and since the plant it was spent upon is not in rate base, it is unfair to the Company to reduce rate base.

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b. Yes. UNS Gas has the use until it is invested in the projects it was specifically advanced to fund. UNS Gas has not attempted to exclude any portion of customer advances not yet spent or spent on plant included in rate base.

c. Please see UNS Gas' response to 11.32.b. above.

d. UNS Gas does not reduce CWIP by advances prior to calculating AFUDC.

e. The only suggestion in Rule 103 that Customer Advances should be deducted from rate base is a line in the form schedule B-1. However, that schedule does not expressly address the circumstance where the advance is related to plant that is not yet in rate base. This rule only controls the general filing format of the rate application, not the final ratemaking decision by the Commission. (See e.g. Decision No. 69914 (Sept. 27, 2007) approving non-deduction of certain advances from rate base.) The rule does not -- and should not -- preclude the Commission from exercising judgment and fairness to insure proper matching and equitable treatment of the shareholders' capital investments. Deducting advances from rate base when the advance is related to plant that is not yet in rate base results in a mismatch and is inequitable because the Company is unable to earn a return on all of its investment in plant that is in rate base.

f. Please see UNS Gas' response to 11.32.e. above.

g. Please see UNS Gas' response to 11.32.b. above.

h. UNS Gas does not hold customer advances received in an escrow account.

i. UNS Gas is not requesting any returns on non-investor supplied capital in this proceeding. As the customer advance reduction in rate base is being interpreted by Staff and RUCO – the Company is being unfairly denied a return on investor supplied capital in rate base.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

**UNS GAS, INC.'S RESPONSE TO
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RUCO 11.36 Refer to Mr. Dukes' rebuttal testimony at page 29-30.

a. Provide the documents relied upon by Mr. Dukes for each amount mentioned on page 29.
b. Provide all vehicle fuel price invoices UNSG has for the months of January through June 2009.
c. Provide the fuel price invoices UNSG has for the month of July 2009.
d. Would the Company's actual invoices for fuel over a recent period be an appropriate reflection of the current known price levels? If not, explain fully why not.
e. Refer to page 30, line 26. Please identify the specific period constituting "the past three years".
f. Does UNSG have information from which an average fuel price for the 36-month period ("last three years") ending June 30, 2009 could be computed? If not, explain fully why not. If so, please provide that information.
g. What fuel prices has UNSG used in its 2009 operating expense budget? Provide the related documentation.
h. What fuel prices has UNSG used in its 2009, 2010 and 2011 budgets and/or forecasts? Provide the related documentation.

RESPONSE:

a. Mr. Dukes reviewed the fuel prices on the websites noted on page 29 of his Rebuttal Testimony, but did not retain screen prints of the prices.

b. Please see RUCO 11.36(b & c), Bates Nos. UNSG(0571)10197 to UNSG(0571)10234 on the enclosed CD for the requested information.

c. Please see UNS Gas' response to RUCO 11.36.b above.

d. Using recent prices is one method of arriving at a price per gallon for fleet fuel. However, as noted in Mr. Dukes' Rebuttal Testimony on page 30, the significant and continued volatility of the cost of fuel per gallon is better addressed by using a longer period of actual information.

e. The period constituting "the past three years" refers to calendar years 2006, 2007 and 2008. This information was included in the backup to Mr. Dukes' Rebuttal Testimony in response to RUCO Data Request 10.1 as Excel file "RUCO 10.1 – Income – Fleet Fuel Expense".

f. Yes. Please see the Excel file RUCO 11.36(f) on the enclosed CD for the average fuel price for the 36 months ending June 30, 2009.

g. Please see the PDF file RUCO 11.36(g-h), Bates No. UNSG(0571)10235 on the enclosed CD for the requested information.

h. Please see UNS Gas' response to RUCO 11.36.g above.

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The Excel file on the enclosed CD is not identified by Bates numbers.

RESPONDENT: Dallas Dukes, Gary Kelly, Julie Gomez & Janet Zaidenberg-Schrum

WITNESS: Dallas Dukes

UNS GAS, INC.
FLEET FUEL EXPENSE - RUCO 11.36f
36 MONTH AVERAGE FUEL PRICE
July 2006 through June 2009

Calculated using revised data from J. Gomez 6/26/09 & 7/16/09

	Cost per Gallon
Jul-06	$3.01
Aug-06	$2.98
Sep-06	$2.67
Oct-06	$2.46
Nov-06	$2.47
Dec-06	$2.51
Jan-07	$2.43
Feb-07	$2.48
Mar-07	$2.74
Apr-07	$2.99
May-07	$3.09
Jun-07	$3.07
Jul-07	$3.00
Aug-07	$2.85
Sep-07	$2.85
Oct-07	$3.00
Nov-07	$3.26
Dec-07	$3.23
Jan-08	$3.17
Feb-08	$3.26
Mar-08	$3.58
Apr-08	$3.73
May-08	$4.05
Jun-08	$4.35
Jul-08	$4.32
Aug-08	$3.97
Sep-08	$3.78
Oct-08	$3.24
Nov-08	$2.50
Dec-08	$2.04
Jan-09	$2.12
Feb-09	$2.20
Mar-09	$2.12
Apr-09	$2.32
May-09	$2.28
Jun-09	$2.62
Average	**$2.96**

Zaidenberg-Schrum, Janet

From: Kelly, Gary
Sent: Thursday, July 16, 2009 2:20 PM
To: Zaidenberg-Schrum, Janet
Subject: UNSG Rate Case - RUCO 11.36g & h

From: Kelly, Gary
Sent: Thursday, July 16, 2009 1:38 PM
To: Zaidenberg-Schrum, Janet
Cc: Gomez, Julie; Cordero, Jessica
Subject: RE: UNSG Rate Case - RUCO Data Request for Fleet Fuel

Below is the information that you requested.

The budgeted price for fuel in 2009 was $4.05 per gallon based on approximately 207,000 gallons used annually

The figures listed below have been submitted for the 2010 and 2011 budget

2010 - $2.75 per gallon, 207,000 gallons used annually. Total budgeted amount $569,250
2011 - $2.95 per gallon, 207,000 gallons used annually. Total budgeted amount $610,650

The numbers listed above include gasoline and diesel.

Please let me know if you need additional information.
GK

**UNS GAS, INC.'S RESPONSE TO
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RUCO 11.38 Refer to Mr. Grant's rebuttal testimony at page 24.

a. Provide complete supporting documentation for each amount shown in the table, including a detailed identification and explanation for all assumptions used in the projections.

b. Provide a detailed listing of all items in the "Operating Expenses" line of the table, including but not limited to the following:
   i. SERP
   ii. Incentive compensation expense
   iii. Stock-based compensation expense
   iv. Outside legal expense
   v. Rate case expense

c. Identify the amount of common equity in the table for each year that is not supporting Arizona adjusted jurisdictional original cost rate base.

d. Identify all assumptions, and provide all calculations, related to the amount of interest expense in the table. For each year, provide a listing of all debt issuances outstanding, the interest rate for each (including how it was calculated) and the amount of interest. Also show how the interest expense was allocated between (1) debt supporting AZ jurisdictional rate base and (2) debt supporting other items on UNSG's balance sheet that are not included in rate base.

e. What income tax rate did UNSG use to compute the Income Tax Expense for each year in the table? Provide supporting calculations. If an income tax rate that is different than the rate proposed by UNSG in the rate case was used, provide a complete reconciliation. Identify, quantify and explain each reconciling item fully.

f. Please identify fully and in detail how UNSG has reflected 2008 and 2009 bonus tax depreciation in its 2008 actual results and 2009 projections. Include complete supporting calculations.

RESPONSE:

a. The referenced table on page 24 of Mr. Grant's Rebuttal Testimony is based on the 2008 financial statements for UNS Gas and a financial forecast for the period 2009-2011 that were included in the workpapers to Mr. Grant's Rebuttal Testimony and previously provided in response to data request RUCO 10.1. For 2008 values, please refer to the 2008 income statement for UNS Gas provided in Mr. Grant's Rebuttal workpapers. For 2009-2011 values, please refer to the financial forecast provided in Mr. Grant's Rebuttal workpapers. Specifically, please refer to the forecast page with the heading "UNSG – Income Statement." There are 12 columns of data on that page, the first four of which reflect the forecast presented in Mr. Grant's Direct Testimony, the middle four of which reflect the financial forecast presented in Mr. Grant's Rebuttal Testimony, and the final four of which reflect the difference between these two forecasts. It is the middle four columns of data on this page that were used to populate the table on page 24 of Mr. Grant's Rebuttal Testimony. A line-by-line explanation of the values appearing on the referenced table is presented below, along with references to the financial forecast in Mr. Grant's Rebuttal workpapers and other supporting information.

Gross Margin

Gross margin is equal to total revenues minus purchased gas expense. The calculation of gross margin, along with the various line items comprising total revenues and purchased gas expense, may be found in the forecasted income statement provided in Mr. Grant's Rebuttal workpapers. For 2010, the first full year under new rates in the Company's financial forecast, UNS Gas forecasts its gross margin to be $64,975,000.

Most of the Company's gross margin is derived from retail delivery revenues, which, along with demand-side management ("DSM") program revenues, are shown as "Retail T&D Revenues" on the Company's forecasted income statement. For 2010, the first full year under new rates in the Company's financial forecast, UNS Gas forecasts retail delivery revenues of $56,927,000 and DSM program revenues of $1,044,000.

Delivery revenues from transport customers and long-term contract customers (the Griffith and Black Mountain generating stations) also contribute to gross margin. Delivery revenues from transport customers and the Griffith Power Plant are reflected as "Wholesale Transmission Revenues" on the Company's forecasted income statement. The $570,000 in annual delivery revenues from the Black Mountain Generating Station are lumped in with gas sales to UNS Electric in "Wholesale Energy Sales" on the Company's forecasted income statement. For 2010, the first full year under new rates in the Company's financial forecast, UNS Gas forecasts total transport and long-term contract delivery revenues of $4,912,000.

Miscellaneous customer service charges, which include connect/disconnect fees, late payment fees, etc. also contribute to gross margin and are reflected as "Other Revenues" on the Company's forecasted income statement. For 2010, the first full year under new rates in the Company's financial forecast, UNS Gas forecasts Other Revenues of $1,626,000.

Margins derived from sales of gas to transport customers under the Negotiated Sales Program ("NSP") also contribute to gross margin. Fifty percent of these margins are retained by the Company, while the other fifty percent are credited to the PGA balance. For 2010, the first full year under new rates in the Company's financial forecast, UNS Gas forecasts its share of NSP margins to be $466,000.

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This amount can be derived from the forecasted income statement in Mr. Grant's Rebuttal work papers by subtracting purchased gas expense (equal to "Purchased Power and Gas for Resale" plus "Deferred Fuel Expense") from purchased gas revenues (equal to "PPFAC/PGA Revenues" plus "Wholesale Energy Sales" minus $570,000 in Black Mountain delivery revenues included in "Wholesale Energy Sales").

In summary, for 2010, the first full year under new rates in the Company's financial forecast, the forecasted gross margin is as follows:

$56,927,000	Retail Delivery Revenues
1,044,000	DSM Program Revenues
4,912,000	Transport and Long-Term Contract Delivery Revenues
1,626,000	Other Revenues
466,000	NSP Margins
$64,975,000	Gross Margin

For 2011, the forecasted gross margin is as follows:

$57,983,000	Retail Delivery Revenues
1,076,000	DSM Program Revenues
4,912,000	Transport and Long-Term Contract Delivery Revenues
1,691,000	Other Revenues
437,000	NSP Margins
$66,099,000	Gross Margin

By comparison, the actual gross margin in 2008 was $55,424,000. The forecasted gross margin for 2009, which reflects three months of actual results, eight months of forecasted results under current rates, and one month of forecasted results under the Company's requested rates, is little changed at $55,532,000.

Based on a comparison of the 2008 actual gross margin to the forecasted 2010 gross margin, the Company is forecasting a total increase in gross margin of $9.6 million. Of this, $9.3 million is attributable to the requested rate increase, partially offset by a $0.2 million reduction in retail revenue related to a decline in sales.

The following tables provide additional detail on the Company's forecast of retail delivery revenues and transport customer delivery revenues. Additional detail supporting the Company's forecast of retail revenues is also being provided in the four Excel files named RUCO 11.38 UNS Gas_Non-Industrial Sales ACTMAR09 forecast.xls, RUCO 11.38 UNS Gas_Industrial Sales ACTMAR09 forecast.xls, RUCO 11.38 UNS Gas_Non-Industrial Revenue ACTMAR09 forecast.xls, and RUCO 11.38 UNS Gas_Industrial Revenue ACTMAR09 forecast.xls.

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Retail Sales and Delivery Revenues

		2010		2011
Retail Sales (therms)				
Residential		71,248,000		73,491,000
Commercial		30,258,000		30,444,000
Industrial		1,780,000		1,780,000
Public Authority		6,654,000		6,633,000
Total Retail Sales		109,940,000		112,348,000
Average Delivery Rates ($/therm)				
Residential	$	0.603	$	0.598
Commercial	$	0.384	$	0.384
Industrial	$	0.170	$	0.170
Public Authority	$	0.310	$	0.310
Average Delivery Rates	$	0.518	$	0.518
Retail Delivery Revenues				
Residential	$	42,947,000	$	43,937,000
Commercial		11,615,000		11,688,000
Industrial		302,000		302,000
Public Authority		2,062,000		2,056,000
Total Retail Delivery Revenues	$	56,927,000	$	57,983,000

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Transport and Long-Term Contract Delivery Revenue

	2010	2011
Transport Sales and Delivery Revenues		
Transport Sales (therms)	40,748,000	40,893,000
Average Delivery Rates ($ / therm)	$ 0.085	$ 0.085
Transport Delivery Revenues	$ 3,477,000	$ 3,477,000
Total Long-Term Contract Delivery Revenues	$ 1,435,000	$ 1,435,000
Total Transport and Long-Term Contract Delivery Revenue	**$ 4,912,000**	**$ 4,912,000**

Operating Expenses

Total operating expenses represent the sum of (i) Operation and Maintenance Expenses, (ii) Depreciation Expense, (iii) Taxes Other than Income Taxes and (iv) Other Amortization Expense. Each of these line items may be found in the forecasted income statement in Mr. Grant's Rebuttal workpapers.

For 2009, which reflects three months of actual results and nine months of forecast information, the forecast amount for total operating expenses is as follows:

$26,798	Operations and Maintenance Expenses
7,286	Depreciation Expense
3,048	Taxes Other than Income Taxes
89	Other Amortization Expense
$40,592	Total Operating Expenses

For 2010, the first full year under new rates in the Company's financial forecast, the forecast amount for total operating expenses is as follows:

$29,422	Operations and Maintenance Expenses
7,717	Depreciation Expense
3,194	Taxes Other than Income Taxes
258	Other Amortization Expense
$40,592	Total Operating Expenses

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For 2011, the forecast amount for total operating expenses is as follows:

$30,765	Operations and Maintenance Expenses
8,135	Depreciation Expense
3,433	Taxes Other than Income Taxes
167	Other Amortization Expense
$42,499	Total Operating Expenses

The current year (2009) forecast of Operations and Maintenance ("O&M") Expense is based on the Company's 2009 operating budget, which is updated throughout the year for forecasting purposes with actual year-to-date spending and budget re-projections for the balance of the year. The long-term forecast of O&M expense is based on the approved 2009 budget escalated using a 4% annual escalation rate. The only components of O&M expense that are not subject to the annual escalation rate are DSM program costs and vehicle depreciation expense which are forecasted separately. The approved 2009 O&M budget is being provided in the Excel file named RUCO 11.38 UNS Gas 2009 Budget.xls. The following table shows the derivation of forecasted O&M expense for 2010 and 2011:

Operations and Maintenance $ in thousands	**Approved 2009 Budget**	**2010 Forecast**	**2011 Forecast**
General O&M	$18,802	$19,554	$20,336
SERP	113	118	122
Incentive Compensation Expense	664	691	718
Outside Legal Expense	256	266	277
Vehicle Depreciation	832	890	1,102
Bad Debt Expense	1,000	1,040	1,082
Intercompany Expenses	4,701	4,889	5,084
Pension Expense	896	931	969
DSM Program Expense	824	1,044	1,076
Total Operations and Maintenance Expenses	$28,087	$29,422	$30,765

Depreciation expense is forecasted based on the current balance of plant in service, forecasted additions and retirement to plant in service, applicable plant depreciation rates, and forecasted amortization of the acquisition adjustment arising from the Company's 2003 purchase of Citizen's gas distribution system.

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Detail supporting the Company's forecast of depreciation expense is being provided in the Excel file named RUCO 11.38 UNS Gas ACTMAR09 - depreciation expense and property taxes.xls.

Taxes Other than Income Taxes are forecasted based on the current balance of plant in service, forecasted additions and retirement to plant in service, applicable property tax rates, and a forecast of payroll taxes based on budgeted labor costs. Detail supporting the Company's forecast of property tax expense is being provided in the Excel file named RUCO 11.38 UNS Gas ACTMAR09 - depreciation expense and property taxes.xls.

Other Amortization Expense in the forecast is based on the Company's estimate of rate case expense recovery. For 2010, the Company has assumed amortization expense relating to both the current rate case and previous rate case. For 2011, the Company is forecasting expenses relating only to the current rate case.

Operating Income

Operating Income = Gross Margin – Total Operating Expenses.

Other Income – Net

Forecasted Other Income is comprised of interest on marketable securities and the allowance for equity funds used during construction. These two amounts are shown separately on the forecasted income statement included in Mr. Grant's Rebuttal workpapers. Interest on marketable securities is based on a forecast of the Company's cash balances and a forecast of short-term interest rates that can be earned on these balances. The forecasted short-term investment rate is based on the forward curve for LIBOR less 0.50%. For 2010 and 2011 the forecasted short-term investment rates are 0.74% and 1.79%, respectively. The forecasted allowance for equity funds used during construction is based on the forecasted balance of CWIP and the equity portion of the Company's AFUDC rate.

Interest Expense

Interest expense during the forecast period is comprised of (i) interest on the balance of long-term notes outstanding, (ii) amortization of issuance costs on the long-term notes outstanding, and (iii) commitment fees and letter of credit fees relating to the Company's bank credit facility. As may be seen in the forecasted income statement provided in Mr. Grant's Rebuttal workpapers, interest on the long-term notes is forecasted at $6,230,000 in 2010 and $6,472,000 in 2011. The amount for 2010 reflects the current interest rate of 6.23% on the Company's $100 million balance of long-term notes. A higher interest expense is forecasted in 2011 due to the anticipated refinancing of $50 million of maturing long-term notes with

$60 million of new long-term notes bearing the same interest rate. Other interest costs are forecasted to remain at approximately $100,000 per year. Since no short-term borrowing is forecast, no interest on short-term borrowing is forecast.

<u>Pre-Tax Income</u>

Pre-Tax Income = Operating Income + Other Income – Interest Expense

<u>Income Tax Expense</u>

Income tax expense is forecasted by applying a composite federal/state income tax rate of 39.615% to the Company's forecast of pre-tax income.

<u>Net Income</u>

Net income = Pre-Tax Income – Income Tax Expense

<u>Ending Common Equity</u>

Ending Common Equity = Previous Balance + Net Income – Dividends Paid

See the forecasted balance sheet in Mr. Grant's rebuttal workpapers for the ending common equity balances.

<u>Return on Average Equity</u>

ROE = Net Income / ((Beginning Common Equity + Ending Common Equity)/2)

ROE in 2008 = 9.2% = $8,538,000 / (($88,265,000 + $96,684,000)/2)

ROE in 2009 = 7.2% = $7,270,000 / (($96,684,000 + $103,948,000)/2)

ROE in 2010 = 10.1% = $11,013,000 / (($103,948,000 + $114,961,000)/2)

ROE in 2011 = 9.0% = $10,544,000 / (($114,961,000 + $120,233,000)/2)

b. Please see UNS Gas' response to RUCO 11.38.a. above for line items included in "Operating Expenses," the detailed line items included in the 2009 operating budget, and an explanation of how 2010 and 2011 O&M expenses are escalated from 2009 budget spending levels.

   i. Please see Operations and Maintenance Expenses table provided in response to RUCO 11.38.a. above.

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ii. Please see Operations and Maintenance Expenses table provided in response to RUCO 11.38.a. above. Incentive compensation expense and stock-based compensation expense are shown as one line item on this table.

iii. Please See Operations and Maintenance Expenses table provided in response to RUCO 11.38.a. above. Incentive compensation expense and stock-based compensation expense are shown as one line item on this table.

iv. Please see Operations and Maintenance Expenses table provided in response to RUCO 11.38.a. above.

v. See discussion of "Other Amortization Expense" provided in response to RUCO 11.38.a. above.

c. No such allocation of common equity has been performed. However, since only a small portion of the Company's plant in service is not included in rate base (i.e., plant serving the Griffith and Black Mountain generating stations), any allocation of common equity to non-rate base investment would be quite small.

d. Please see the response to RUCO 11.38.a. above for an explanation of forecasted interest expense. No allocation of forecasted interest expense between "AZ jurisdictional rate base" and "other items on UNSG's balance sheet" has been performed. However, since only a small portion of the Company's test-year plant in service is not included in rate base (e.g., plant serving the Griffith and Black Mountain generating stations), any allocation of interest expense to non-rate base investment would be quite small.

e. The combined effective tax rate used to compute the Income Tax Expense for the table was 39.615%. That effective tax rate was calculated using a state tax rate estimate of 7.1% and a federal tax rate estimate of 32.515%. The combined effective tax rate proposed by UNS Gas in the rate case was 38.598%. The 38.598% was calculated using a state tax rate of 6.968% and a federal tax rate of 31.630%.

The combined effective tax rate proposed in the rate case was calculated using a state tax rate specific to Arizona and the current federal rate. The combined effective tax rate used for the forecast table was a composite tax rate applicable to UniSource Energy Corporation ("UniSource"). If this higher composite tax rate applicable to UniSource had been used to calculate the revenue requirement for UNS Gas, the Company's requested revenue requirement would have been $192,000 higher.

UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009

f. The amounts in the referenced table on page 24 of Mr. Grant's Rebuttal Testimony are not affected by bonus tax depreciation. While bonus tax depreciation does affect the current portion of the Company's income tax liability, it has no bearing on the accrual of income tax expense presented in the table on page 24 of Mr. Grant's Rebuttal Testimony.

RESPONDENT: Kentton C. Grant and Martha Pritz

WITNESS: Kentton C. Grant

UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009

RUCO 11.40 Refer to Mr. Dukes' rebuttal testimony at page 9-10.

a. Provide all documentation relied upon by Mr. Dukes for the statement at page 10, lines 12-13: "At this time we know the increases attributable to the portion of the workforce that are classified and have contracts in place."
b. Provide the dollar amount of payroll expense increase that is related to "the portion of the workforce that are classified and have contracts in place." Include supporting calculations.
c. Is UNSG aware of any other businesses in Arizona that have reduced or curtailed scheduled wage increases because of the poor economic climate? If not, explain fully why not. If so, please explain fully UNSG's knowledge on this subject.
d. Is UNSG aware of any other utilities that have curtailed previously budgeted wage increases because of the poor economic climate? If not, explain fully why not. If so, please explain fully UNSG's knowledge on this subject.
e. Does UNSG agree that the economic climate in Arizona in mid-2009 is worse than in each of the last Southwest Gas filings? If not, explain fully why not.
f. Please identify the specific RUCO testimony and portions thereof in "each of the last three Southwest Gas filings" to which Mr. Dukes is referring on page 10, line 5.

RESPONSE:

a. Please see RUCO 11.40(a), Bates No. UNSG(0571)10238, on the enclosed CD.

b. The pro forma payroll adjustment for the classified employee increase in 2010 was based on an assumed 3% increase and is consistent with the supporting documentation provided in UNS Gas' response to RUCO 11.40.a. The amount of payroll expense adjustment attributable to the 2010 increase for classified employees is $129,654. The unclassified portion is $96,088.

c. UNS Gas has performed no study to identify the wage activity of other Arizona companies in the present economy.

d. UNS Gas has performed no study to identify the wage activity of other Arizona Utilities in the present economy.

e. Yes.

f. RUCO's position in those cases, including citation to the RUCO testimony, is set forth as follows: Decision No. 64172, page 10, lines 19-21; Decision

**UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009**

No. 68487, page 12, lines 24-25; and Decision No. 70665, page 10, lines 6-10.

RESPONDENT: Regulatory Department

WITNESS: Dallas Dukes

Dukes, Dallas

From: Poturalski, Heidi
Sent: Tuesday, June 09, 2009 3:42 PM
To: Dukes, Dallas
Cc: Bracamonte, Steve
Subject: RE: UNS Gas Case

RUCO 11.40a

Hi Dallas. We just concluded negotiations with Local 1116 and they will receive a 2.25% increase on 6-24-09, and then a 2.75% increase on 1-4-2010, 1-3-2011 and 1-2-2012.

* The Local 387 contract expires before the next wage increases for 2010 so I don't have any data on those yet as we will start negotiations with them towards the end of the year.

The Local 769 contact does have wages for 2010 and they receive a 3.3% increase effective 1-4-10.

From: Dukes, Dallas
Sent: Tuesday, June 09, 2009 3:17 PM
To: Poturalski, Heidi
Cc: Bracamonte, Steve
Subject: UNS Gas Case
Importance: High

* = will be negotiated prior to year end, but will be in range with other two.
Dallas Dukes 6/9/09

Heidi, do you have information for anything for 2010? Specifically, have we got any contracts for the classified groups that have already approved 2010 wage increases?

Thanks!

RUCO 1.56 Wage Rate Increases. Refer to page 19 of Dallas Dukes' testimony. Please provide the wage rate increases granted by the Company by date and employee category for 2007, 2008 and 2009.

RESPONSE: Please see UNS Gas' response to TF 6.94 in Staff's sixth set of data requests. An expansion of the response to include dates and to update the response with 2009 information is provided below:

The budgeted and actual merit increases for employees represented by Local 1116 in 2007 was 3% effective 1-8-07, in 2008 was 3% effective 1-7-08 and in 2009 was 1.5% effective 1-5-09.

The budgeted and actual merit increases for employees represented by Local 387 in 2007 was 3% effective 3-1-07, in 2008 was 3.5% effective 3-1-08 and 2009 was 3.5% effective 3-1-09.

The budgeted and average merit increases for non-represented employees for 2007

UNS GAS, INC.'S RESPONSE TO
RUCO'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-08-0571
July 22, 2009

RUCO 11.46 Refer to Mr. Dukes' rebuttal testimony at page 31. Please provide the specific adjustment, and all related supporting calculations, that UNSG believes would be necessary to "correct" the Staff postage adjustment to reflect the correct annualized number of customers. Include all related Excel files and supporting workpapers.

RESPONSE: Please see the Excel file RUCO 11.46 on the enclosed CD for the original Staff and revised postage expense adjustment as requested.

The Excel file on the enclosed CD is not identified by Bates numbers.

RESPONDENT: Janet Zaidenberg-Schrum

WITNESS: Dallas Dukes

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Postage Expense Adjustment
Test Yeat Ended June 30, 2008

AS REVISED BY UNSG PER DUKES REBUTTAL TESTIMONY (PAGE 31) & PER ACC STAFF RESPONSE TO UNSG DATA REQUEST 2.15

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Number of Customer Bills - Unadjusted		1,739,076	Co. Schedule H-2
2	Increase in Postage Rates '09		$0.02	
3	09 increase in postage rates/Unadjusted customers	$	34,782	Line 1 * Line 2
4	UNSG Customer Annualization (difference between actual & adjusted customers on an annual basis per Bentley Erdwurm rebuttal testimony)		(4,139)	UNSG Schedule H2 P1
5	Staff Customer Annualization Postage	$	(1,821)	Line 4 * .44
6	Postage Expense Adjustment - Increase Expense	$	32,960	Line 3 + Line 5
7	Less: UNSG Postage Expense Adjustment As Filed (Bates Nos. UNSG0571/02494 & UNSG0571/02555 - 02562)		$12,750	Misc Expenses Pro Forma
8	Incremental Staff Postage Expense Adjustment	$	20,210	Line 6 - Line 7

UNS GAS, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2008

ADJUSTMENT NAME:	Miscellaneous Expenses
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	September 29, 2008
PREPARED BY:	Mina Briggs & Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs & Janet Zaidenberg-Schrum
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
880	Other Expenses	$27,698	
903	Customer Records and Collection		$14,616
920	Administrative and General Salaries		$302,616
921	Office Supplies and Expenses		$11,124
923	Outside Services Employed		$434,641
925	Injuries and Damages		$198
926	Employee Pension and Benefits		$56,791
930.2	Miscellaneous General Expenses		$7,496
408	Other		$14,853
	Sponsorships		
874	Mains and Services		$8,167
921	Office Supplies and Expenses		$1,630
930	Miscellaneous General Expenses		$15,617
	Postage Expense		
903	**Customer Records and Collection**	**$12,750**	
	ENTRY TOTAL	**$40,448**	**$867,749**

NET ENTRY **$827,301**

Reason for Adjustment

To remove test year expense that should not be included in the revenue requirement because they are for out-of-period activity, they are not reflective of test year activity that should be recovered from customers, or that are year-end accruals not reflective of test year activity.

To increase postage expense to reflect the $.02 rate increase effective May 12, 2008.

UNSG Pro Forma Adjustment - Miscellaneous Expenses (for Postage Expense - Summary Pages)
Bates Nos. UNSG0571/02494 & UNSG0571/02555

✓

UNS GAS, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2008

ADJUSTMENT NAME:	Miscellaneous Expenses
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	September 29, 2008
PREPARED BY:	Mina Briggs & Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs & Janet Zaidenberg-Schrum
REVIEWED BY:	Dallas Dukes DD

JZS 9/29/08 / MB 9/29/08

FERC ACCT	FERC ACCOUNT DESCRIPTION		DEBIT	CREDIT
880	Other Expenses	~ 1a	$27,698	
903	Customer Records and Collection	~ 1b		$14,616
920	Administrative and General Salaries	~ 6a		$302,616
921	Office Supplies and Expenses	~ 1c		$11,124
923	Outside Services Employed	~ 6c		$434,641
925	Injuries and Damages	~ 6d		$198
926	Employee Pension and Benefits	~ 6e		$56,791
930.2	Miscellaneous General Expenses	~ 1d		$7,496
408	Other	~ 6g		$14,853
	Sponsorships			
874	Mains and Services	~ 8a		$8,167
921	Office Supplies and Expenses	~ 8b		$1,630
930	Miscellaneous General Expenses	~ 8c		$15,617
	Postage Expense			
903	Customer Records and Collection	~ 9a	$12,750	
	ENTRY TOTAL		**$40,448**	**$867,749**
	NET ENTRY			**$827,301**

Reason for Adjustment

To remove test year expense that should not be included in the revenue requirement because they are for out-of-period activity, they are not reflective of test year activity that should be recovered from customers, or that are year-end accruals not reflective of test year activity.

To increase postage expense to reflect the $.02 rate increase effective May 12, 2008.

9/29/2008 4:17 PM

UNSG Pro Forma Adjustment - Miscellaneous Expenses (for Postage Expense - Summary Pages)
Bates Nos. UNSG0571/02494 & UNSG0571/02555

1B 9/29/08

UNS GAS, INC.
POSTAGE EXPENSE - TEST YEAR ENDED JUNE 30, 2008
SUMMARY OF FERC ACCOUNT ADJUSTMENTS

FERC	Test Year Expense	Test Year %	Test Year Adjustment
0874	$5	0.0008%	$0
0875	$190	0.0282%	$4
0880	$5,015	0.7453%	$95
0887	$310	0.0460%	$6
0894	$261	0.0387%	$5
0902	$119	0.0177%	$2
0903	$633,444	94.1280%	$12,001
0908	$500	0.0743%	$9
0909	$169	0.0251%	$3
0921	$5,373	0.7984%	$102
0930	$27,575	4.0976%	$522
	$672,960	100.0000%	$12,750 a

Note: Increase in postage expense attributed 100% to FERC 903 since allocation to FERC accounts based on test year activity results in insignificant amounts.

9/29/2008 4:17 PM 9

UNS Gas, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Year Ended June 30, 2008

Line No.	Class of Service	Rate Schedule Present	Proposed	Actual Therm Sales	Actual Average Number of Customers	Actual Average Therm per Customer	Test Year End Adjustments	Adjusted Therm Sales	Adjusted Average Number of Customers	Adjusted Average Therm per Customer	Line No
1	Residential Service	R-10	R-10	70,723,037	125,602	563	(2,656,075)	68,066,962	124,959	545	1
2	Residential Service Cares	R-12	R-12	3,478,376	6,745	516	55,060	3,533,436	7,077	499	2
3	Small Volume Commercial Service	C-20	C-20	30,119,256	11,423	2,637	(827,599)	29,291,657	11,385	2,573	3
4	Large Volume Commercial Service	C-22	C-22	1,442,578	15	95,115	(104,334)	1,338,244	14	95,589	4
5	Commercial Transportation	C-22T1	C-22T1	3,344,634	10	321,085	(303,749)	3,040,885	9	337,876	5
6	Small Volume Industrial Service	I-30	I-30	502,579	18	28,448	51,187	553,766	20	27,688	6
7	Large Volume Industrial Service	I-32	I-32	1,246,247	6	219,926	(33,594)	1,212,653	5	242,531	7
8	Industrial Transportation	I-32 T1	I-32 T1	11,443,573	12	973,921	138,953	11,582,526	13	890,964	8
9	Industrial Transportation - Contracts	I-32 T1C	I-32 T1C	7,564,291	3	2,521,430	(2,396,706)	5,167,584	3	1,722,528	
10	T2 Transportation	I-32 T2	I-32 T2	1,151,133	1	1,151,133	0	1,151,133	1	1,151,133	
11	Small Volume Public Authority	P-40	P-40	5,797,679	1,069	5,423	(185,370)	5,612,308	1,072	5,236	11
12	Large Volume Public Authority	P-42	P-42	1,225,072	5	245,014	(32,942)	1,192,130	5	238,426	12
13	Public Authority Transportation	P-42T1	P-42T1	5,127,210	7	715,425	270,621	5,397,831	8	674,729	13
14	Special Gas Light Service	P-44	P-44	145,406	2	72,703	0	145,406	2	72,703	14
15	Irrigation Service	I-60	I-60	104,267	5	20,853	(712)	103,554	5	20,711	15
16	Total Gas Service			143,415,337	144,923	990	(6,025,261)	137,390,076	144,578	950	16

Note: Some transportation customers have more than one meter which is accounted for in this schedule.

THIS DATA REQUEST RESPONSE WAS STILL PRESENTING AN INCORRECT POSTAGE EXPENSE CALCULATION

Dr.. Fish notes that two cents of the total postage for additional customers is accounted for in Line 3 of Schedule THF-C9, but this is incorrect. The two cent postage rate increase applied to existing unadjusted customer bills was accounted for on line 3 of Staff's calculation. The entire new 44 cent postage rate should be applied to the incremental customer bills resulting from the customer annualization calculation - not the 42 cents as noted by Dr. Fish below.

ARIZONA CORPORATION COMMISSION
DOCKET NO. G-04204A-08-0571
STAFF'S RESPONSE TO UNS GAS, INC.'S
SECOND SET OF DATA REQUESTS
July 1, 2009

UNSG 2.15 **Postage Expense (page 25)** –Please explain why the adjustment to Postage Expense of $49,594 in Schedule THF-C9, Line 6, is the sum of the number of customers on Line 4 and the dollar amount of the postage annualization on Line 5. If this is an error, please provide corrected calculations.

RESPONSE: **Dr. Fish's customer annualization resulted in 34,440 more customer bills being sent than Company's customer annualization. These additional customers would require postage for their bills. Two cents of the total postage for the additional customers is accounted for in line 3 of Schedule THF-C9, but $.42 of the postage for the additional customers is not accounted for and should be. This amount is $14,465. The total postage pro forma adjustment, then is $34,782 from line 3 plus $14,465 for a total pro forma adjustment of $49,247, not $49,594.**

RESPONDENT: **DR. THOMAS FISH**

WITNESS: **DR. THOMAS FISH**

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Postage Expense Adjustment
Test Yeat Ended June 30, 2008

STAFF ORIGINAL

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Number of Customer Bills		1,739,076	Co. Schedule H-2
2	Increase in Postage Rates '09		$0.02	
3	09 increase in postage rates/Company cust	$	34,782	Line 1 * Line 2
4	Staff Customer Annualization		34,440	Staff Schedule THF - C.1a
5	Staff Customer Annualization Postage	$	15,154	Line 4 * .44
6	Postage Expense Adjustment	$	49,594	Line 3 * Line 5

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Attachment RCS-9
Copies of Confidential UNS Gas' Responses to Data Requests and Workpapers Referenced in the Surrebuttal Testimony and Schedules of Ralph C. Smith

****UNS Gas Confidential Information Has Been Redacted****

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
RUCO-11-5	FERC Docket No. RP08-426 (without attachments)	Yes	3	2 - 4
RUCO-11-11	UNSG intervention in FERC proceedings	Yes	4	5 - 8
RUCO-11-20	Annual cost reductions from UNS Gas Lobby office closings	Yes	3	9 - 11
RUCO-11-22	Debit-balance ADIT and related Accrued Liabilities	Yes	15	12 - 26
RUCO-11-27 - attachment only	Purchased gas payment lag	Yes	7	27 - 33
RUCO-11-35	Outside Legal costs, budgets for 2008, 2009 and 2010	Yes	2	34 - 35
RUCO-11-39	Bonus tax depreciation and impact on ADIT	Yes	4	36 - 39
	Total Pages Including this Page		39	

ATTACHMENT RCS-9 PAGES 2-39 ARE CONFIDENTIAL AND HAVE BEEN REDACTED